UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period from to

Commission File No. 1-11680

GulfTerra Energy Partners, L.P.

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0396023** (I.R.S. Employer Identification No.)
4 Greenway Plaza **Houston, Texas** (Address of Principal Executive Offices)	**77046** (Zip Code)

Registrant's Telephone Number, Including Area Code: **(832) 676-4853**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

The registrant had 59,964,566 common units outstanding as of August 6, 2004.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)
(Unaudited)

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003[1]	2004	2003[1]
Operating revenues	$225,218	$237,031	$445,557	$467,126
Operating expenses				
Cost of natural gas and other products	60,095	85,385	124,522	176,138
Operation and maintenance	51,967	48,551	100,463	89,195
Depreciation, depletion and amortization	26,080	24,846	52,303	48,543
(Gain) loss on sale of long-lived assets	—	363	(24)	257
	138,142	159,145	277,264	314,133
Operating income	87,076	77,886	168,293	152,993
Earnings from unconsolidated affiliates	3,258	2,987	5,466	6,303
Minority interest income (expense)	—	(47)	12	(80)
Other income	124	309	284	692
Interest and debt expense	26,696	31,838	54,727	66,324
Loss due to early redemptions of debt	16,285	—	16,285	3,762
Income before cumulative effect of accounting change	47,477	49,297	103,043	89,822
Cumulative effect of accounting change	—	—	—	1,690
Net income	$ 47,477	$ 49,297	$103,043	$ 91,512
Income allocation				
Series B unitholders	$ —	$ 3,898	$ —	$ 7,774
General partner				
Income before cumulative effect of accounting change	$ 21,420	$ 15,856	$ 42,549	$ 30,716
Cumulative effect of accounting change	—	—	—	17
	$ 21,420	$ 15,856	$ 42,549	$ 30,733
Common unitholders				
Income before cumulative effect of accounting change	$ 22,022	$ 24,160	$ 51,087	$ 41,614
Cumulative effect of accounting change	—	—	—	1,340
	$ 22,022	$ 24,160	$ 51,087	$ 42,954
Series C unitholders				
Income before cumulative effect of accounting change	$ 4,035	$ 5,383	$ 9,407	$ 9,718
Cumulative effect of accounting change	—	—	—	333
	$ 4,035	$ 5,383	$ 9,407	$ 10,051
Basic and diluted earnings per common unit				
Income before cumulative effect of accounting change	$ 0.37	$ 0.50	$ 0.86	$ 0.90
Cumulative effect of accounting change	—	—	—	0.03
Net income	$ 0.37	$ 0.50	$ 0.86	$ 0.93
Basic weighted average number of common units outstanding	59,649	48,005	59,298	46,024
Diluted weighted average number of common units outstanding	59,886	48,476	59,566	46,302
Distributions declared per common unit	$ 0.710	$ 0.675	$ 1.420	$ 1.350

[1] See Note 1, Basis of Presentation and Summary of Significant Accounting Policies — Revenue Recognition and Cost of Natural Gas and Other Products.

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except unit amounts)
(Unaudited)

	June 30, 2004	December 31, 2003
ASSETS		
Current assets		
Cash and cash equivalents	$ 33,445	$ 30,425
Accounts receivable, net	161,414	154,235
Affiliated note receivable	3,713	3,768
Other current assets	21,670	20,595
Total current assets	220,242	209,023
Property, plant, and equipment, net	2,930,005	2,894,492
Intangible assets	3,177	3,401
Investments in unconsolidated affiliates	203,303	175,747
Other noncurrent assets	29,354	38,917
Total assets	$3,386,081	$3,321,580
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable	$ 148,919	$ 168,133
Accrued interest	8,083	11,199
Current maturities of senior secured term loans	5,000	3,000
Other current liabilities	41,328	27,035
Total current liabilities	203,330	209,367
Revolving credit facility	462,000	382,000
Senior secured term loans, less current maturities	493,500	297,000
Long-term debt	923,016	1,129,807
Other noncurrent liabilities	42,089	49,043
Total liabilities	2,123,935	2,067,217
Commitments and contingencies		
Minority interest	1,801	1,777
Partners' capital		
Limited partners		
Common units; 59,698,129 and 58,404,649 units issued and outstanding	912,236	898,072
Series C units; 10,937,500 units issued and outstanding	334,892	341,350
General partner	13,217	13,164
Total partners' capital	1,260,345	1,252,586
Total liabilities and partners' capital	$3,386,081	$3,321,580

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
Cash flows from operating activities		
Net income	$ 103,043	$ 91,512
Less cumulative effect of accounting change	—	1,690
Income before cumulative effect of accounting change	103,043	89,822
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	52,303	48,543
Distributed earnings of unconsolidated affiliates		
Earnings from unconsolidated affiliates	(5,466)	(6,303)
Distributions from unconsolidated affiliates	1,450	8,230
(Gain) loss on sale of long-lived assets	(24)	257
Loss due to write-off of unamortized debt issuance costs	3,884	3,762
Amortization of debt issuance costs, premiums and discounts	2,651	4,016
Other noncash items	6,352	1,341
Working capital changes, net of acquisitions and noncash transactions	(27,961)	(15,502)
Net cash provided by operating activities	136,232	134,166
Cash flows from investing activities		
Additions to property, plant and equipment	(86,107)	(207,011)
Proceeds from sale and retirement of assets	197	3,215
Additions to investments in unconsolidated affiliates	(17,947)	(197)
Net cash used in investing activities	(103,857)	(203,993)
Cash flows from financing activities		
Net proceeds from revolving credit facility	386,932	223,000
Repayments of revolving credit facility	(307,000)	(298,854)
Net proceeds from senior secured term loan	199,651	—
Repayment of senior secured term loan	(1,500)	(2,500)
Repayment of senior secured acquisition term loan	—	(237,500)
Net proceeds from (debt issuance costs for) issuance of long-term debt	(52)	292,479
Repayments of long-term debt	(214,085)	—
Net proceeds from issuance of common units, Series F convertible units and conversion of Series F convertible units	48,536	182,182
Distributions to partners	(142,317)	(107,427)
Contribution from general partner	480	1
Net cash (used in) provided by financing activities	(29,355)	51,381
Increase (decrease) in cash and cash equivalents	3,020	(18,446)
Cash and cash equivalents at beginning of period	30,425	36,099
Cash and cash equivalents at end of period	$ 33,445	$ 17,653
Schedule of noncash financing activities:		
Redemption of Series B preference units contributed from our general partner	$ —	$ 1,788

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE LOSS
(In thousands)
(Unaudited)

Comprehensive Income

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Net income	$47,477	$49,297	$103,043	$91,512
Other comprehensive income (loss)	2,127	272	(2,172)	(5,443)
Total comprehensive income	$49,604	$49,569	$100,871	$86,069

Accumulated Other Comprehensive Loss

	June 30, 2004	December 31, 2003
Beginning balance	$ (9,027)	$ (5,622)
Unrealized mark-to-market losses on cash flow hedges arising during period	(10,716)	(12,924)
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	8,544	10,018
Accumulated other comprehensive loss from investment in unconsolidated affiliate	—	(499)
Ending balance	$(11,199)	$ (9,027)
Accumulated other comprehensive loss allocated to:		
Common units' interest	$ (9,305)	$ (7,488)
Series C units' interest	$ (1,742)	$ (1,409)
General partner's interests	$ (152)	$ (130)

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

We are a publicly held Delaware master limited partnership (MLP) established in 1993 for the purpose of providing midstream energy services, including gathering, transportation, fractionation, storage and other related activities, for producers of natural gas and oil, onshore and offshore in the Gulf of Mexico. Our sole general partner is GulfTerra Energy Company, L.L.C., a Delaware limited liability company that is owned 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise Products Partners L.P. (Enterprise), a publicly traded MLP. References to "us", "we", "our", or "GulfTerra" are intended to mean the consolidated business and operations of GulfTerra Energy Partners, L.P.

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2003 Annual Report on Form 10-K, as amended, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2004, and for the quarters and six months ended June 30, 2004 and 2003, are unaudited. We derived the balance sheet as of December 31, 2003, from the audited balance sheet filed in our 2003 Annual Report on Form 10-K, as amended. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature, to fairly present our interim period results. Information for interim periods may not depict the results of operations for the entire year. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our previously reported net income or partners' capital.

With respect to our Texas intrastate pipeline system, which we acquired in April 2002, we had previously used the pre-acquisition accounting methodology for the cash settlement of natural gas imbalance receivables, which included the cash settlement amounts as a component of operating revenues and cost of natural gas and other products. However, effective January 1, 2004, we have conformed our accounting for cash settlements on that system to the same method we use to account for imbalance receivable settlements on our other systems, which method accounts for these types of cash settlements as an adjustment to cost of natural gas and other products. We have determined that this revision is not material to our previously reported financial statements. Accordingly, we have not revised our previously filed financial statements to reflect this change in methodology.

Unbilled Trade Receivables and Accrued Gas Purchase Costs

As of June 30, 2004 and December 31, 2003, we had included in accounts receivable, net on our balance sheets, unbilled trade receivables of $74.6 million and $63.1 million. Also, as of June 30, 2004 and December 31, 2003, we had included in accounts payable on our balance sheets, accrued gas purchase costs of $20.0 million and $15.4 million.

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts that we believe are uncollectible. We review collectibility regularly and adjust the allowance as necessary, primarily under the specific identification method. As of June 30, 2004 and December 31, 2003, our allowance was $4.0 million.

As generally used in the energy industry and in this document, the following terms have the following meanings:

/d	= per day	MBbls	= thousand barrels
Bbl	= barrel	MDth	= thousand dekatherms
Bcf	= billion cubic feet	MMcf	= million cubic feet

When we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

Revenue Recognition and Cost of Natural Gas and Other Products

Typhoon Oil Pipeline, a wholly owned subsidiary, has transportation agreements with BHP and ChevronTexaco which provide that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. As disclosed in our 2003 Annual Report on Form 10-K, as amended, we now record revenue from these buy/sell transactions upon delivery of the oil based on the net amount billed to the producers. For the quarter and six months ended June 30, 2003, we reduced by $73.1 million and $121.9 million our revenues and cost of natural gas and other products to conform to the current period presentation. This revision had no effect on operating income, net income or partners' capital.

Accounting for Stock-Based Compensation

We use the intrinsic value method established in Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, to value unit options issued to individuals who are on our general partner's current board of directors and for those grants made prior to El Paso Corporation's acquisition of our general partner in August 1998 under our Omnibus Plan and Director Plan. For the quarters and six months ended June 30, 2004 and 2003, the cost of this stock-based compensation had no impact on our net income, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. We use the provisions of Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation*, to account for all of our other stock-based compensation programs. Compensation expense for the quarter and six months ended June 30, 2004 and 2003 is reflected in the table below for our stock-based compensation programs accounted for under the provisions of SFAS No. 123.

If compensation expense had been determined by applying the fair value method in SFAS No. 123 to all of our grants, our net income allocated to common unitholders and net income per common unit would have approximated the pro forma amounts below:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands, except per unit amounts)			
Net income as reported	$47,477	$49,297	$103,043	$91,512
Add: Stock-based employee compensation expense included in reported net income	133	366	267	679
Less: Stock-based employee compensation expense determined under fair value based method	(159)	(406)	(300)	(720)
Pro forma net income	$47,451	$49,257	$103,010	$91,471
Pro forma net income allocated to common unitholders	$21,996	$24,120	$ 51,054	$42,913
Earnings per common unit:				
Basic and diluted, as reported and pro forma	$ 0.37	$ 0.50	$ 0.86	$ 0.93

The effects of applying the provisions of SFAS No. 123 in this pro forma disclosure for all of our stock-based compensation programs may not be indicative of future amounts.

Our remaining accounting policies are consistent with those discussed in our 2003 Annual Report on Form 10-K, as amended, except as discussed below.

Inventory

In June 2004, we purchased pipeline inventory, consisting of parts and materials, from El Paso Natural Gas Company (EPNG); see Note 8, Related Party Transactions, for further discussion. This inventory is included on our balance sheet as of June 30, 2004, in other current assets. We use the average cost method to account for our inventory and we value our inventory at the lower of its cost or market value.

Consolidation of Variable Interest Entities

During the first quarter of 2004, we adopted the provisions of Financial Accounting Standards Board Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) No. 51*, as replaced by FIN No. 46-R. This interpretation defines a variable interest entity (VIE) as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity and excludes certain joint ventures of other entities that meet the characteristics of a business. Our adoption of FIN No. 46 had no effect on our reported results or financial position.

Two-Class Method of Computing Earnings per Common Unit

During the second quarter of 2004, we adopted the provisions of Emerging Issues Task Force (EITF) 03-6, *Participating Securities and the Two-Class Method under SFAS No. 128.* EITF 03-6 requires the use of the two-class method of determining basic earnings per unit. Under the two-class method, distributions to equity owners are subtracted from earnings, and any remaining earnings would be allocated to the various classes of owners in proportion to their right to receive distributions as if those earnings had been distributed. The total of distributions to each class of owner plus the amount allocated to each class would be used to compute earnings per unit for that class. Because our distributions to owners exceeded earnings during the periods presented, as has historically been the case, the two-class method did not produce any change in result from the way we have traditionally computed earnings per unit. As a result, the adoption of this standard had no effect on our earnings per unit calculation for the quarters and six months ended June 30, 2004 and 2003.

2. MERGER WITH ENTERPRISE

On December 15, 2003, we, along with Enterprise and El Paso Corporation, announced that we had executed definitive agreements to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs.

In April 2004, Enterprise and El Paso Corporation amended their agreement with respect to the ownership of Enterprise's general partner interest upon the completion of our merger with Enterprise.

As originally envisioned in the merger agreement, El Paso Corporation was to contribute its 50-percent ownership interest in our general partner to Enterprise's general partner, in exchange for a 50-percent ownership interest in Enterprise's general partner. Under the amended transaction, El Paso Corporation will still contribute its 50-percent ownership interest in our general partner to Enterprise's general partner, but in exchange, El Paso Corporation will receive a 9.9 percent ownership interest in Enterprise's general partner and $370 million in cash. The remaining 90.1 percent ownership interest in Enterprise's general partner will continue to be owned by affiliates of privately-held Enterprise Products Company.

The remaining transactions with respect to our merger with Enterprise are unchanged. These include:

- the payment of $500 million in cash from Enterprise to El Paso Corporation for approximately 13.8 million units, which include 2.9 million of our common units and all of our Series C units owned by El Paso Corporation; and
- the exchange of 1.81 Enterprise common units for each GulfTerra common unit owned by GulfTerra's unitholders, including the remaining approximately 7.5 million GulfTerra common units owned by El Paso Corporation.

On June 22, 2004, Enterprise's registration statement on Form S-4 was declared effective by the SEC. On July 29, 2004, our common and Series C unitholders approved the adoption of the merger agreement to combine us with a wholly-owned subsidiary of Enterprise. See Part II, Other Information, Item 4. Submission of Matters to a Vote of Security Holders, for the results of the unitholder vote. We expect the completion of the merger to occur in the third quarter of 2004, although it remains subject to review by the Federal Trade Commission (FTC) and the satisfaction of other conditions to close.

Merger-Related Costs

As a result of the pending merger with Enterprise, we determined that it was in our and our unitholders' best interest to offer selected employees of El Paso Corporation incentives to continue to focus on the business of the partnership during the merger process. We have accounted for these incentives under the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* In March 2004, we recorded a liability and a related deferred charge of $4.3 million, which was reflected in other current liabilities and other current assets on our balance sheets. Our liability was estimated based upon the number of employees accepting the offer and the discounted amount they are expected to be paid. We are amortizing the deferred charge to expense ratably over the expected period of the services required in order to qualify for receiving the payments. We expect to amortize the entire expense by merger close. During the quarter and six months ended June 30, 2004, we amortized $2.2 million and $2.8 million to expense. As of June 30, 2004, the remaining deferred charge was $1.5 million. If our expectations of future amounts to be paid or the period of service to be rendered change, we will adjust our liability.

Additionally, during the first quarter of 2004, we recognized an expense of $3.5 million associated with a fairness opinion we received on our pending merger with Enterprise. During the quarter and six months ended June 30, 2004, we recognized expenses for legal and audit fees totaling $1.4 million and $1.5 million associated with our pending merger with Enterprise. All of our merger-related costs are included in operation and maintenance expenses on our statements of income and are allocated across all of our operating segments.

3. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	June 30, 2004	December 31, 2003
	(In thousands)	
Property, plant and equipment, at cost[1]		
Pipelines	$2,526,336	$2,487,102
Platforms and facilities	164,212	121,105
Processing plants	305,904	305,904
Oil and natural gas properties	131,100	131,100
Storage facilities	338,735	337,535
Construction work-in-progress	386,875	383,640
	3,853,162	3,766,386
Less accumulated depreciation, depletion and amortization	923,157	871,894
Total property, plant and equipment, net	$2,930,005	$2,894,492

(1) Includes leasehold acquisition costs with an unamortized balance of $2.1 million and $3.2 million at June 30, 2004 and December 31, 2003. One interpretation being considered relative to SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Intangible Assets*, is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on our consolidated balance sheets. We will continue to include these costs in property, plant, and equipment until definitive guidance is provided.

4. FINANCING TRANSACTIONS

The close of the merger with Enterprise, announced in December 2003, will constitute a change of control, and thus a default, under our credit facility. To avoid a default, our credit facility must be refinanced or amended at or before the closing of the merger. Enterprise has stated that it currently intends that our credit facility be refinanced before the closing of the merger and that, if that does not occur, there are reasonable grounds to believe that our existing credit facility will be amended prior to the closing of the merger. If the facility is not amended or refinanced prior to closing, the resulting default would have a material adverse effect on the combined company. In addition, the closing of the merger will constitute a change of control under our indentures, and we will be required to offer to repurchase our outstanding senior subordinated notes (and possibly our senior notes) at 101 percent of their principal amount after the closing. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the closing of the merger. On August 4, 2004, Enterprise announced that one of its subsidiaries commenced cash tender offers to purchase any and all of our outstanding senior subordinated and senior notes. In connection with the tender offers, Enterprise is soliciting consents to proposed amendments that would eliminate certain restrictive covenants and default provisions contained in the indentures governing the notes. Enterprise is commencing the tender offers and consent solicitations in anticipation of completing the merger, and the merger is a non-waivable condition to the completion of the tender offers and consent solicitations. We and Enterprise can agree on the date of the merger closing after the receipt of all necessary approvals. We do not intend to close until appropriate financing or other arrangements are in place.

Credit Facility

As of June 30, 2004, our credit facility consisted of three parts: the revolving credit facility maturing in 2006, a senior secured term loan maturing in 2007 and a senior secured term loan maturing in 2008. Our credit facility is guaranteed by us and each of our subsidiaries, excluding our unrestricted subsidiaries, as detailed in Note 12, and is collateralized with substantially all of our assets (excluding the assets of our unrestricted subsidiaries). The interest rates we are charged on our credit facility are determined at our option using one of two indices that include (i) a variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank or the federal funds rate plus 0.5%); or (ii) LIBOR. The interest rate we are charged is contingent upon our leverage ratio, as defined in our credit facility, and credit ratings we are assigned by Standard & Poor's (S&P) or Moody's. Depending on the credit ratings on our senior secured credit facility and our leverage ratio, the interest we are charged varies from 1.00% to 2.75% over LIBOR or 0.00% to 1.75% over the variable base rate discussed above. Additionally, we pay commitment fees on the unused portion of our revolving credit facility at rates that vary from 0.30% to 0.50%.

Our credit facility contains covenants that include restrictions on our and our subsidiaries' ability to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies and amend some of our contracts, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries and could restrict our ability to make distributions to our unitholders. In addition, our failure to comply with the provisions of any of the covenants could also be a breach of our merger agreement with Enterprise.

Revolving Credit Facility

At June 30, 2004, we had $462 million outstanding under our revolving credit facility at an average interest rate of 3.16%. We may elect that all or a portion of the revolving credit facility bear interest at either the variable base rate described above increased by 1.0% or LIBOR increased by 2.0%. The amount available to us at June 30, 2004, under this facility was $218 million.

Senior Secured Term Loans

In May 2004, we obtained an additional $200 million senior secured term loan in addition to our already existing $300 million senior secured term loan. We initially used this additional $200 million to temporarily reduce indebtedness under our $700 million revolving credit facility and subsequently to fund the redemption of our $175 million aggregate principal amount of 10³/₈% senior subordinated notes due 2009. Our new senior secured term loan, which we may prepay in full at any time, is payable in semi-annual installments of $1.0 million in November and May of each year for the first six installments, and the remaining balance is due at maturity in October 2007. Our already-existing senior secured term loan is payable in semi-annual installments of $1.5 million in June and December of each year for the first nine installments, and the remaining balance is due at maturity in December 2008. On both senior secured term loans, we may elect that all or a portion of the senior secured term loans bear interest at either 1.25% over the variable base rate described above or LIBOR increased by 2.25%. As of June 30, 2004, we had $498.5 million outstanding on our senior secured term loans with an average interest rate of 3.65%.

Long-Term Debt

In April 2004, we redeemed, at a premium, approximately $39.1 million in principal amount of our 8¹/₂% senior subordinated notes due June 2010. In connection with the redemption of the notes, we recognized additional expense during the quarter ended June 30, 2004, totaling $4.1 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs.

In June 2004, we redeemed all of our outstanding $175 million aggregate principal amount of 10³/₈% senior subordinated notes due 2009. The notes were redeemed at a redemption price of 105.2% of the principal amount, plus accrued and unpaid interest up to June 1, 2004. In connection with the redemption of the notes, we recognized additional expense during the quarter ended June 30, 2004, totaling $12.2 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs.

We accounted for the costs on both redemptions in accordance with the provisions of SFAS No. 145, *Rescission of Financial Accounting Standards Board (FASB) Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.*

Our senior and senior subordinated notes include provisions that, among other things, restrict our ability and the ability of our subsidiaries (excluding our unrestricted subsidiaries) to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies, and enter into sale and lease-back transactions, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries in addition to restricting our ability to make distributions to our unitholders. In addition, our failure to comply with the provisions of any of the covenants could also be a breach of our merger agreement with Enterprise. Many restrictive covenants associated with our senior notes will effectively be removed following a period of 90 consecutive days during which they are rated Baa3 or higher by Moody's or BBB− or higher by S&P, and some of the more restrictive covenants associated with some (but not all) of our senior subordinated notes will be suspended should they be similarly rated.

In July 2003, to achieve a more balanced mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8¹/₂% senior subordinated notes due 2011. With this swap agreement, we paid the counterparty a LIBOR based interest rate plus a spread of 4.20% and received a fixed rate of 8¹/₂%. The net amount to be paid or received under the interest rate swap contract was added to or deducted from the interest and debt expense on our senior subordinated notes for which the swap contract was executed, payable semi-annually in June and December. In December 2003, we received $2.8 million related to the interest rate swap contract. We accounted for this derivative as a fair value hedge under SFAS No. 133. In March 2004, we terminated our fixed to floating interest rate swap with our counterparty. The value of the transaction at termination was zero, and as such neither we, nor our counterparty, were required to make any additional payments. Also, neither we, nor our counterparty, have any future obligations under this transaction.

Industrial Development Revenue Bonds

In April 2004, we reduced the sales tax assessable by the State of Mississippi related to our Petal natural gas storage expansion and pipeline project completed in September 2002 by completing that project's qualification for tax incentives available under the Mississippi Business Finance Act (MBFA). To complete the qualification, Petal Gas Storage, L.L.C. (Petal), our indirect, wholly-owned subsidiary, borrowed $52 million from the Mississippi Business Finance Corporation (MBFC) pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52 million in Industrial Development Revenue Bonds to GulfTerra Field Services, L.L.C., our direct, wholly–owned subsidiary. The loan agreement and the Industrial Development Revenue Bonds have identical interest rates of 6.25% and maturities of fifteen years. The bonds and tax exemptions are authorized under the MBFA. Petal may repay the loan agreement without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $0.6 million on our balance sheet as of June 30, 2004. We have also netted the interest expense and interest income amount of $0.6 million on our income statements for the quarter and six months ended June 30, 2004. Our presentation of the Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, *Offsetting of Amounts Related to Certain Contracts,* and SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* since we have the ability and intent to offset these items.

Other Credit Facilities

Poseidon

Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, was party to a $185 million credit agreement, under which it had $123 million outstanding at December 31, 2003. In January 2004, Poseidon amended its credit agreement and decreased the availability to $170 million. The amended facility matures in January 2008. The outstanding balance from the previous facility was transferred to the new facility. The interest rates Poseidon is charged on balances outstanding under its credit facility are variable and depend on its ratio of total debt to earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon's assets. As of June 30, 2004, Poseidon had $111 million outstanding with an average interest rate of 3.47%.

Poseidon's credit agreement contains covenants such as restrictions on debt levels, liens, mergers, the sales of assets and dividends and requirements to maintain certain financial ratios.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of the $123 million outstanding at 3.49% through January 2004. This interest rate swap expired on January 9, 2004.

Deepwater Gateway

Deepwater Gateway, an unconsolidated affiliate in which we have a 50 percent joint venture interest and that constructed the Marco Polo tension leg platform (TLP), obtained a $155 million project finance loan from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. Construction of the Marco Polo TLP was completed during the first quarter of 2004, and in June 2004, Deepwater Gateway converted the project finance loan into a term loan with a final maturity date of June 2009. The term loan is payable in twenty equal quarterly installments of $5.5 million beginning September 30, 2004, and the remaining outstanding principal of $45 million is due on the maturity date in June 2009. Interest rates are variable and the loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the term loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of June 30, 2004, Deepwater Gateway had $155 million outstanding under the term loan at an average interest rate of 3.15% and had not paid us or any of our subsidiaries any distributions.

Cameron Highway

Cameron Highway Oil Pipeline Company (Cameron Highway), an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest, entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes.

The construction loan bears interest at a variable rate. Upon completion of the construction, which is expected during the fourth quarter of 2004, the construction loan will convert to a term loan maturing July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly principal payments of $8.1 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by January 2006, the construction loan and senior secured notes become fully due and payable. At June 30, 2004, Cameron Highway had $171 million outstanding under the construction loan at an average interest rate of 4.56%.

The interest rate on Cameron Highway's senior secured notes is 3.25% over the rate on 10-year U.S. Treasury securities. Principal payments of $4 million are due quarterly from September 2008 through December 2011, $6 million each from March 2012 through December 2012, and $5 million each from March 2013 through the principal maturity date of December 2013. At June 30, 2004, Cameron Highway had $100 million outstanding under the senior secured notes at an average interest rate of 7.36%.

The project loan facility as a whole is secured by (1) substantially all of Cameron Highway's assets, including, upon conversion, a debt service reserve capital account, and (2) all of the equity interest in Cameron Highway. Other than the pledge of our equity interest and our construction obligations under the relevant producer agreements, the debt is non-recourse to us. The construction loan and senior secured notes prohibit Cameron Highway from making distributions to us until the construction loan is converted into a term loan and Cameron Highway meets certain financial requirements.

Debt Maturity Table

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the remainder of 2004 and the following 4 years and in total thereafter are as follows at June 30, 2004 (in thousands):

2004	$ 2,500
2005	5,000
2006	467,000
2007	198,000
2008	288,000
Thereafter	921,515
Total long-term debt and other financing obligations, including current maturities	$1,882,015

Loss Due to Early Redemptions of Debt

We recognized losses associated with early redemptions of debt as follows (in thousands):

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Loss due to payment of redemption premiums	$12,401	$—	$12,401	$ —
Loss due to write-off of unamortized debt issuance costs	3,884	—	3,884	3,762
	$16,285	$—	$16,285	$3,762

5. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for these investments are as follows:

Six Months Ended June 30, 2004
(In thousands)

	Coyote	Deepwater Gateway[(1)]	Cameron Highway[(2)]	Poseidon	Total
End of period ownership interest	50%	50%	50%	36%	
Operating results data:					
Operating revenues	$3,600	$ 6,300	$ —	$18,116	
Other income	2	10	84	23	
Operating expenses	(296)	(63)	—	(2,602)	
Depreciation	(721)	(1,962)	—	(4,930)	
Other expenses	(341)	(1,485)	(382)	(1,827)	
Net income	$2,244	$ 2,800	$(298)	$ 8,780	
Our share:					
Allocated income (loss)	$1,122	$ 1,400	$(149)	$ 3,161	
Adjustments[(3)]	(4)	(191)	92	65	
Earnings (loss) from unconsolidated affiliates	$1,118	$ 1,209	$ (57)	$ 3,226	$5,466[(4)]
Allocated distributions	$1,450	$ —	$ —	$ —	$1,450

Six Months Ended June 30, 2003
(In thousands)

	Coyote	Deepwater Gateway[(1)]	Poseidon	Total
End of period ownership interest	50%	50%	36%	
Operating results data:				
Operating revenues	$3,825	$—	$23,207	
Other income	4	23	35	
Operating expenses	(242)	—	(2,160)	
Depreciation	(690)	—	(4,169)	
Other expenses	(387)	(5)	(2,835)	
Net income	$2,510	$18	$14,078	
Our share:				
Allocated income	$1,255	$ 9	$ 5,068	
Adjustments[(3)]	—	(9)	(20)	
Earnings from unconsolidated affiliate	$1,255	$—	$ 5,048	$6,303
Allocated distributions	$1,750	$—	$ 6,480	$8,230

(1) The Marco Polo TLP, which is owned by Deepwater Gateway L.L.C., was installed in the first quarter of 2004. First production and thus volumetric payments started in July 2004. In April 2004, Deepwater Gateway began receiving monthly demand payments of $2.1 million. Prior to the TLP installation, Deepwater Gateway was a development stage company; therefore there were no operating revenues or operating expenses. However, it did incur organizational expenses and received interest income.

(2) Cameron Highway Oil Pipeline Company is a development stage company; therefore there are no operating revenues or operating expenses. Since its formation in June 2003, it has incurred organizational expenses and received interest income.

(3) We recorded adjustments primarily for differences from estimated earnings reported in our Quarterly Report on Form 10-Q and actual earnings reported in the unaudited financial statements of our unconsolidated affiliates.

(4) Total earnings from unconsolidated affiliates includes a $30 thousand reduction associated with the true-up of the gain on the sale of our interest in Copper Eagle.

6. PARTNERS' CAPITAL

Cash distributions

The following table reflects our per unit cash distributions to our common unitholders and the total distributions paid to our common unitholders, Series C unitholder and general partner during the six months ended June 30, 2004:

Month Paid	Common Unit	Common Unitholders	Series C Unitholder	General Partner
	(Per unit)		(In millions)	
February	$0.71	$41.5	$7.8	$21.3
May	$0.71	$42.4	$7.8	$21.7

In July 2004, we declared a cash distribution of $0.71 per common unit and Series C unit, $50.3 million in the aggregate, for the quarter ended June 30, 2004, which we will pay on August 13, 2004, to holders of record as of July 30, 2004. Also in August 2004, we will pay our general partner $21.2 million in incentive distributions. At the current distribution rate, our general partner receives approximately 30.2 percent of our total cash distributions for its role as our general partner.

Series F Convertible Units

In connection with a public offering in May 2003, we issued 80 Series F convertible units convertible into a maximum of 8,329,679 common units and comprised of two separate detachable units. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until the date we merge with Enterprise (subject to other defined extension rights). The Series F2 units are convertible into up to $40 million of common units prior to March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser (i) of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75, or (ii) the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units, (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven business days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units, assuming we had received a conversion notice on June 30, 2004 and August 5, 2004, was $38.47 and $37.10 per common unit. Holders of Series F convertible units are not entitled to vote or to receive distributions. The value of the Series F convertible units was $2.6 million as of June 30, 2004, and is included in partners' capital as a component of common units capital.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at June 30, 2004 and December 31, 2003.

In July 2004, 10 Series F1 convertible units were converted into 261,437 common units, for which the holder of the convertible units paid us $10 million. Additionally, our general partner contributed to us $0.1 million in cash in order to maintain its one percent general partner interest.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million. Additionally, our general partner contributed to us $0.4 million in cash in order to maintain its one percent general partner interest.

Any Series F1 convertible units for which a conversion notice has not been delivered prior to the merger closing date, or termination of the merger, will expire upon the closing, or termination, of the merger with Enterprise. Any Series F2 convertible units outstanding at the merger date will be converted into rights to receive Enterprise common units, subject to the restrictions governing the Series F units. The number of Enterprise common units and the price per unit at conversion will be adjusted based on the 1.81 exchange ratio.

Option Plans

During the quarter ended June 30, 2004, we granted 4,962 restricted units at a fair value per unit of $38.31 and 8,000 unit options with a grant price of $38.31 to non-employee directors of our Board of Directors under our Director Plan. We accounted for the restricted units in accordance with SFAS No. 123. Under SFAS No. 123, the fair value of these issuances is reflected as deferred compensation and is amortized to compensation expense over the period of service, which we have estimated to be one year. The unit options issued have been accounted for in accordance with APB No. 25. As these options were issued at market value, under the provisions of APB No. 25, no entries were made at the issuance date.

Total unamortized deferred compensation as of June 30, 2004 and December 31, 2003, was approximately $1.2 million and $1.5 million. Deferred compensation is reflected as a reduction of partners' capital and is allocated 1 percent to our general partner and 99 percent to our limited partners.

Net proceeds from unit options exercised during the quarter and six months ended June 30, 2004, were approximately $0.3 million and $4.9 million. Net proceeds from unit options exercised during the quarter and six months ended June 30, 2003, were $0.5 million.

At the close of the merger, any outstanding restricted units issued to (1) employees of El Paso Field Services who will become employees of Enterprise or (2) non-employee directors of our general partner's Board of Directors who will be a member of the Board of Directors of the merged company will convert to Enterprise common units with the same terms, except that the number of Enterprise common units will be adjusted based on the 1.81 exchange ratio. Any outstanding restricted units issued to employees of El Paso Field Services who will not be employees of Enterprise or to non-employee directors of our general partner's Board of Directors who will not be a member of the Board of Directors of the merged company will vest on the merger date and be exchanged for Enterprise common units at the 1.81 exchange ratio.

Unit Option Buyout

Under the merger agreement with Enterprise, we are obligated to repurchase, at reasonable prices, before the effective time of the merger, all outstanding employee and director unit options that have not been exercised or otherwise canceled. Approximately 1,000,000 common unit options were outstanding at June 30, 2004, held by 28 current and former employees and directors. Since we do not have the right under our option plan to force our option holders to sell their options, we were required to negotiate a separate option purchase agreement individually with each option holder. The governance and compensation committee of our general partner's board of directors engaged an independent financial advisor to assist in the determination of the appropriate repurchase prices for the outstanding options. Subsequent to June 30, 2004, we entered into option purchase agreements with all the option holders under which we have agreed to purchase for cash and/or common units, and the option holders have agreed to sell, any options that remain outstanding on the merger closing date for a negotiated price. Each option purchase agreement permits the option holder to exercise any or all of his or her options at any time and from time to time prior to the merger closing. Based on information provided by the financial advisor engaged by the governance and compensation committee, we estimate the value, in the aggregate, of the outstanding options to be repurchased is approximately $13 million.

7. EARNINGS PER COMMON UNIT

The following table sets forth the computation of basic and diluted earnings per common unit (in thousands, except per unit amounts):

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Numerator:				
Numerator for basic earnings per common unit —				
Income before cumulative effect of accounting change	$22,022	$24,160	$51,087	$41,614
Cumulative effect of accounting change	—	—	—	1,340
	$22,022	$24,160	$51,087	$42,954
Denominator:				
Denominator for basic earnings per common unit — weighted-average common units	59,649	48,005	59,298	46,024
Effect of dilutive securities:				
Unit options	212	146	244	112
Restricted units	22	9	23	8
Series F convertible units	3	316	1	158
Denominator for diluted earnings per common unit — adjusted for weighted-average common units	59,886	48,476	59,566	46,302
Basic and diluted earnings per common unit				
Income before cumulative effect of accounting change	$ 0.37	$ 0.50	$ 0.86	$ 0.90
Cumulative effect of accounting change	—	—	—	0.03
	$ 0.37	$ 0.50	$ 0.86	$ 0.93

8. RELATED PARTY TRANSACTIONS

There have been no changes to our related party relationships, except as described below, from those described in Note 10 of our audited financial statements filed in our 2003 Annual Report on Form 10-K, as amended.

Revenues received from related parties for the quarters ended June 30, 2004 and 2003, were approximately 17 percent and 15 percent of our total revenue. Revenues received from related parties for the six months ended June 30, 2004 and 2003, were approximately 17 percent and 14 percent of our total revenue.

Our transactions with related parties and affiliates are as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands)			
Revenues received from related parties:				
Natural gas pipelines and plants	$22,827	$26,064	$43,513	$49,014
Oil and NGL logistics	14,847	8,975	30,247	15,844
	$37,674	$35,039	$73,760	$64,858
Expenses paid to related parties:				
Cost of natural gas and other products	$ 6,496	$ 5,842	$16,011	$20,797
Operation and maintenance	23,078	22,093	45,665	45,810
	$29,574	$27,935	$61,676	$66,607
Reimbursements received from related parties:				
Operation and maintenance	$ 663	$ 676	$ 1,629	$ 1,201

The following table provides summary data categorized by our related parties:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands)			
Revenues received from related parties:				
El Paso Corporation				
El Paso Merchant Energy North America Company	$ 823	$ 7,791	$ 1,508	$18,603
El Paso Production Company	2,358	2,074	4,620	4,432
Tennessee Gas Pipeline Company	227	38	227	93
El Paso Field Services	33,835	25,136	66,791	41,730
Enterprise	431	—	614	—
	$37,674	$35,039	$73,760	$64,858
Cost of natural gas and other products paid to related parties:				
El Paso Corporation				
El Paso Merchant Energy North America Company	$ 6,202	$ 5,427	$15,257	$15,705
El Paso Field Services	235	346	637	5,023
El Paso Natural Gas Company	20	17	39	17
Southern Natural Gas	39	52	78	52
	$ 6,496	$ 5,842	$16,011	$20,797
Operation and maintenance expenses paid to related parties:				
El Paso Corporation				
El Paso Field Services	$22,988	$21,979	$45,443	$45,603
Unconsolidated Subsidiaries				
Poseidon Oil Pipeline Company	90	114	222	207
	$23,078	$22,093	$45,665	$45,810
Reimbursements received from related parties:				
Unconsolidated Subsidiaries				
Cameron Highway	$ 75	$ —	$ 292	$ —
Deepwater Gateway	21	—	204	—
Poseidon Oil Pipeline Company	567	676	1,133	1,201
	$ 663	$ 676	$ 1,629	$ 1,201

Our accounts receivable due from related parties consisted of the following as of:

	June 30, 2004	December 31, 2003
	(In thousands)	
El Paso Corporation		
El Paso Production Company	$ 955	$ 5,991
El Paso Merchant Energy North America Company	3,644	4,113
Tennessee Gas Pipeline Company	1,479	1,350
El Paso Field Services	18,815	16,571
El Paso Natural Gas Company	3,807	4,255
ANR Pipeline Company	980	1,600
Other	106	830
Enterprise	77	—
	29,863	34,710
Unconsolidated Subsidiaries		
Deepwater Gateway	4,888	3,939
Cameron Highway	2,396	9,302
Poseidon	836	—
Other	—	14
	8,120	13,255
Total	$37,983	$47,965

Our accounts payable due to related parties consisted of the following as of:

	June 30, 2004	December 31, 2003
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 6,222	$ 7,523
El Paso Production Company	410	4,069
El Paso Field Services	4,572	13,869
Tennessee Gas Pipeline Company	271	1,278
El Paso Natural Gas Company	7,561	942
El Paso Corporation	1,014	6,249
Southern Natural Gas	68	1,871
Other	853	667
	20,971	36,468
Unconsolidated Subsidiaries		
Deepwater Gateway	2,601	2,268
Poseidon	772	—
Other	109	134
	3,482	2,402
Total	$24,453	$38,870

Other Matters

Pipeline Inventory Purchase. In June 2004, we executed an agreement with EPNG, a subsidiary of El Paso Corporation, for the purchase of certain parts and materials inventory. We paid approximately $2.1 million for the items purchased and this inventory is included on our balance sheet as of June 30, 2004, in other current assets.

Petal. In September 2003, Petal entered into a nonbinding letter of intent with Southern Natural Gas Company, a subsidiary of El Paso Corporation, regarding the proposed development and sale of a natural gas storage cavern, and the proposed sale of an undivided interest in the Petal pipeline and other facilities related to that natural gas storage cavern. The new storage cavern would be located at our storage complex near Hattiesburg, Mississippi. In June 2004, Petal and Southern Natural Gas Company terminated their letter of intent and Petal announced that it would hold a nonbinding open season to determine market interest for up to 5.0 Bcf of firm natural gas storage capacity, and up to 500,000 MMBtu/d of firm transportation on the Petal pipeline, all available in the third quarter of 2007.

Copper Eagle. In August 2003, Arizona Gas Storage, L.L.C., along with its 50 percent partner APACS Holdings L.L.C., sold their interest in Copper Eagle Gas Storage L.L.C. to EPNG. Copper Eagle Gas Storage is developing a natural gas storage project located outside of Phoenix, Arizona. Arizona Gas Storage, L.L.C. is an indirect 60 percent owned subsidiary of us and 40 percent owned by IntraGas US, a Gaz de France North American subsidiary. APACS Holdings L.L.C. is a wholly owned subsidiary of Pinnacle West Energy, a subsidiary of Pinnacle West Capital Corporation. Under the original agreement, we have the right to receive $6.2 million of the sale proceeds, including a note receivable for $4.9 million to be paid quarterly beginning on January 1, 2004, and ending with a final payment on October 1, 2004. In April 2004, Arizona Gas Storage, L.L.C., APACS Holdings, L.L.C. and EPNG agreed to modify the payment schedule related to the Copper Eagle purchase, and the new payment terms are expected to be finalized during the third quarter of 2004. As of June 30, 2004, we have received principal payments totaling $1.3 million and interest payments totaling $45 thousand from EPNG related to the note receivable.

Indemnifications. In addition to the related party transactions discussed above, pursuant to the terms of many of the purchase and sale agreements we have entered into with various entities controlled directly or indirectly by El Paso Corporation, we have been indemnified for potential future liabilities, expenses and capital requirements above a negotiated threshold. Specifically, an indirect subsidiary of El Paso Corporation has agreed to indemnify us for specific litigation matters to the extent the ultimate resolution of these matters results in judgments against us. For a further discussion of these matters see Note 9, Commitments and Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We have not made any claims during the six months ended June 30, 2004 or 2003. However, for the full year of 2003, we made claims for approximately $5 million of costs incurred during the year ended December 31, 2003, as costs exceeded the established thresholds for 2003.

Wilson Storage Operating Lease Commitment. In connection with our April 2002 purchase of the EPN Holding assets from subsidiaries of El Paso Corporation, we obtained a long-term operating lease commitment related to the Wilson natural gas storage facility, which is operated by one of our direct subsidiaries. From the acquisition date until the second quarter of 2004, El Paso Corporation guaranteed our direct subsidiary's payment and performance under this commitment. In the second quarter of 2004, El Paso Corporation was released from the guarantee and, thus, we now are solely liable for our direct subsidiary's payment and performance under this operating lease agreement.

Capital Contribution Arrangements. We have also entered into capital contribution arrangements with entities owned by El Paso Corporation, including its regulated pipelines, in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. We have an agreement to receive up to $6.1 million, of which $3.0 million has been collected as of June 30, 2004, from ANR Pipeline Company for our Phoenix gathering system, which went into service in July 2004. We expect to receive the remaining amount from ANR Pipeline Company in the third quarter of 2004. The amounts collected are reflected as a reduction in project costs. Regulated pipelines often contribute capital toward the construction costs of gathering facilities owned by others which are, or will be, connected to their pipelines.

Unit Option Buyout/Option Plans. As previously discussed in Note 6, Partners' Capital, we will repurchase employee and director options before the merger and outstanding restricted units will convert to Enterprise restricted units or vest at the merger date.

9. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Grynberg. In 1997, we, along with numerous other energy companies, were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). We, along with numerous other energy companies, are named defendants in *Will Price, et al v. Gas Pipelines and Their Predecessors, et al,* filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands, seek certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that they contend these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied on April 10, 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action petition has been filed as to heating content claims. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In August 2002, we acquired the Big Thicket assets, which consist of the Vidor plant, the Silsbee compressor station and the Big Thicket gathering system located in east Texas, for approximately $11 million from BP America Production Company (BP). Pursuant to the purchase agreement, we have identified environmental conditions that we are working with BP and appropriate regulatory agencies to address. BP has agreed to indemnify us for exposure resulting from activities related to the ownership or operation of these facilities prior to our purchase (i) for a period of three years for non-environmental claims and (ii) until one year following the completion of any environmental remediation for environmental claims. Following expiration of these indemnity periods, we are obligated to indemnify BP for environmental or non-environmental claims. We, along with BP and various other defendants, have been named in the following two lawsuits for claims based on activities occurring prior to our purchase of these facilities.

Christopher Beverly and Gretchen Beverly, individually and on behalf of the estate of John Beverly v. GulfTerra GC, L.P., et. al. In June 2003, the plaintiffs sued us in state district court in Hardin County, Texas, requesting unspecified monetary damages. The plaintiffs are the parents of John Christopher Beverly, a two year old child who died on April 15, 2002, allegedly as the result of his exposure to arsenic, benzene and other harmful chemicals in the water supply. Plaintiffs allege that several defendants are responsible for that contamination, including us and BP. Our connection to the occurrences that are the basis for this suit appears to be our August 2002 purchase of certain assets from BP, including a facility in Hardin County, Texas known as the Silsbee compressor station. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between us and BP, we requested that BP indemnify us for any exposure. BP has agreed to indemnify us in this matter.

Melissa Duvail, et. al., v. GulfTerra GC, L.P., et. al. In June 2003, seventy-four residents of Hardin County, Texas, sued us and others in state district court in Hardin County, Texas, requesting unspecified monetary damages. The plaintiffs allege that they have been exposed to hazardous chemicals, including arsenic and benzene, through their water supply, and that the defendants are responsible for that exposure. As with the Beverly case, our connection with the occurrences that are the basis of this suit appears to be our August 2002 purchase of certain assets from BP, including a facility known as the Silsbee compressor station, which is located in Hardin County, Texas. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between us and BP. BP has agreed to indemnify us for this matter.

Commodity Futures Trading Commission Investigation. In April 2004, we elected to voluntarily cooperate with the Commodity Futures Trading Commission (CFTC) in connection with the CFTC's industry-wide investigation of activities affecting the price of natural gas in the fall of 2003. Specifically, the CFTC requested companies to provide information, on behalf of themselves and their affiliates, relating to storage reports provided to the Energy Information Administration for the period of October 2003 through December 2003. We are cooperating fully with the CFTC's investigation and have provided requested information for the relevant time period regarding our storage operations at our Petal and Wilson fields.

In connection with our April 2002 acquisition of the EPN Holding assets, subsidiaries of El Paso Corporation have agreed to indemnify us against all obligations related to existing legal matters at the acquisition date, including the legal matters involving Leapartners, L.P. discussed below.

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process natural gas in areas of western Texas related to an asset now owned by GulfTerra Holding. In May 2001, the court ruled in favor of Leapartners and entered a judgment against El Paso Field Services of approximately $10 million. El Paso Field Services filed an appeal with the Eighth Court of Appeals in El Paso, Texas. On August 15, 2003 the Court of Appeals reversed the lower court's calculation of post judgment interest but otherwise affirmed the judgment. A petition for review by the Texas Supreme Court was filed, and the Supreme Court has requested full briefing of the issues.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we will establish the necessary accruals. As of June 30, 2004, we had no reserves for our legal matters.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Environmental

Each of our operating segments is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. We expect to make capital expenditures for environmental matters of approximately $7 million in the aggregate for the years 2004 through 2008, primarily to comply with clean air regulations.

As of June 30, 2004 and December 31, 2003, we had a reserve of approximately $21 million, which is included in other non-current liabilities on our balance sheets, for remediation costs expected to be incurred over time associated with mercury gas meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. As part of the April 2002 EPN Holding asset acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities, excluding the remediation costs associated with mercury gas meters, related to the assets we purchased up to the purchase of $752 million. Additionally, as part of the November 2002 San Juan assets acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased up to the purchase price of $764 million. We will be indemnified for liabilities discovered during the proceeding three years from the closing date of these acquisitions. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased.

Shoup Air Permit Violation. On December 16, 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NoE) from the Texas Commission on Environmental Quality (TCEQ) concerning alleged Clean Air Act violations at its Shoup, Texas plant. The NoE included a draft Agreed Order assessing a penalty of $365,750 for the cited violation. The alleged violations pertained to emission limit exceedences, testing, reporting, and recordkeeping issues in 2001. While the NoE was addressed to El Paso Field Services, L.P., the substance of the NoE also concerns equipment at the Shoup plant owned by our subsidiary, GulfTerra GC, L.P. El Paso Field Services, L.P. responded to the NoE challenging several of the allegations and the penalty amount and is awaiting a response from the TCEQ.

While the outcome of our outstanding environmental matters cannot be predicted with certainty, based on the information known to date and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Rates and Regulatory Matters

Marketing Affiliate Final Rule. In November 2003, the Federal Energy Regulatory Commission (FERC) issued a Final Rule extending its standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since our High Island Offshore System (HIOS) natural gas pipeline and Petal natural gas storage facility, including the 60-mile Petal natural gas pipeline, are interstate facilities as defined by the Natural Gas Act, the regulations dictate how HIOS and Petal conduct business and interact with all energy affiliates of El Paso Corporation and us.

The standards of conduct require us, absent a waiver, to functionally separate our HIOS and Petal interstate facilities from our other entities. We must dedicate employees to manage and operate our interstate facilities independently from our other Energy Affiliates. This employee group must function independently and is prohibited from communicating non-public transportation information or customer information to its Energy Affiliates. Separate office facilities and systems are necessary because of the requirement to restrict affiliate access to interstate transportation information. The Final Rule also limits the sharing of employees and offices with Energy Affiliates. The Final Rule was effective June 1, 2004. On February 9, 2004, each transmission provider, including Petal and HIOS, filed with the FERC and posted on the internet website, a plan and scheduling for implementing this Final Rule. On April 8, 2004, we filed for an exemption from the rule on behalf of Petal and HIOS. On April 16, 2004, the FERC issued its order on rehearing which, among other things, affirmed that the Final Rule was needed and extended the implementation date to September 1, 2004. On July 8, 2004, Petal and HIOS filed separate notices with the FERC withdrawing their requests. The FERC has not acted on the requests and they remain pending. However, we believe compliance with this Final Rule should not place an undue burden on us.

Other Regulatory Matters. HIOS is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a FERC approved tariff that governs its operations, terms and conditions of service, and rates. We timely filed a required rate case for HIOS on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee and changes to depreciation rates and negative salvage amortization. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. As of July 1, 2003, HIOS implemented the requested rates, subject to a refund, and has established a reserve for its estimate of its refund obligation. We will continue to review our expected refund obligation as the rate case moves through the hearing process and may increase or decrease the amounts reserved for refund obligation as our expectation changes. The FERC conducted a hearing on this matter and an initial decision from the Administrative Law Judge was provided in April 2004. We have filed briefs on exceptions to this decision. In August 2004, HIOS filed an offer of settlement to resolve all issues in the rate case with the FERC. This settlement is the result of negotiations among HIOS and all but one of the customers participating in the rate case. In addition, the FERC Staff is not a party to the settlement. Comments on the settlement are due on August 25, 2004, and reply comments on September 7, 2004. The settlement is subject to the approval of the FERC.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. This was primarily associated with an unexplained increase in our fuel use which was not contemporaneously collected from our customers. We initially believed a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October 2002. We conducted a thorough review of our operations and were unable to determine the exact cause of the increase in fuel use. The fuel use has since returned to historical levels. As of June 30, 2004, we have recorded gross fuel differences of approximately $7.5 million, which we included in our non-current assets on our balance sheet. In the future, we expect to have an opportunity to file for collection of the fuel differences. However, at this time we are not able to determine what amount, if any, may be collectible from our customers. Any amounts we are unable to resolve or collect from our customers will negatively impact the future results of our natural gas pipelines and plants segment.

In December 1999, GulfTerra Texas filed a petition with the FERC for approval of its rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to GulfTerra Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering service. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. GulfTerra Texas has established a reserve for refunds. In July 2002, GulfTerra Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. On February 25, 2004, the FERC issued an order denying GulfTerra Texas' request for rehearing and ordered GulfTerra Texas to file, within 45 days from the issuance of the order, a calculation of refunds and a refund plan. On March 22, 2004, the FERC extended the 45 day time limit to July 12, 2004. On July 12, 2004, GulfTerra Texas filed its response including its recalculations of rates, plan for unbundling gathering and transmission rates, and its refund plan. The amount of refunds we calculated are immaterial. Additionally, the FERC ordered GulfTerra Texas to file a new rate case or justification of existing rates within three years from the date of the order. In March 2004, GulfTerra Texas filed for rehearing of the triennial rate case requirement, and the request remains pending.

In July 2002, Falcon Gas Storage, a competitor, also requested late intervention and rehearing of the order. Falcon asserts that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering imbalance management services. The FERC denied Falcon's late intervention in February 2004. Meanwhile in December 2002, GulfTerra Texas amended its Statement of Operating Conditions to provide shippers the option of resolving daily imbalances using a third-party imbalance service provider.

Falcon filed a formal complaint in March 2003 at the Railroad Commission of Texas claiming that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering hourly imbalance management services on the GulfTerra Texas system. GulfTerra Texas filed a response specifically denying Falcon's assertions and requesting that the complaint be denied. The hearing on this matter, scheduled for June 29, 2004, has been postponed and no new hearing date has been established. The City Board of Public Service of San Antonio filed an intervention in opposition to Falcon's complaint.

While the outcome of all of our rates and regulatory matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Joint Ventures

We conduct a portion of our business through joint ventures (including our Cameron Highway, Deepwater Gateway and Poseidon joint ventures) we form to construct, operate and finance the development of our onshore and offshore midstream energy businesses. We are obligated to make our proportionate share of additional capital contributions to our joint ventures only to the extent that they are unable to satisfy their obligations from other sources, including proceeds from credit arrangements.

10. ACCOUNTING FOR HEDGING ACTIVITIES

A majority of our commodity purchases and sales, which relate to sales of oil and natural gas associated with our production operations, purchases and sales of natural gas associated with pipeline operations, sales of natural gas liquids and purchases or sales of gas associated with our processing plants and our gathering activities, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities.

We estimate the entire $11.2 million of unrealized losses included in accumulated other comprehensive income at June 30, 2004, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next six months. When our derivative financial instruments are settled, the related amount in accumulated other comprehensive income is recorded in the income statement in operating revenues, cost of natural gas and other products, or interest and debt expense, depending on the item being hedged. The effect of reclassifying these amounts to the income statement line items is recording our earnings for the period related to the hedged items at the "hedged price" under the derivative financial instruments.

In February and August 2003, we entered into derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. As of June 30, 2004 and December 31, 2003, the fair value of these cash flow hedges was a liability of $7.3 million and $5.8 million, as the market price at those dates was higher than the hedge price. For the quarter and six months ended June 30, 2004, we reclassified approximately $2.3 million and $4.0 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. These reclassifications are included in our natural gas pipelines and plants segment. No ineffectiveness exists in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

During 2003, we entered into additional derivative financial instruments to hedge a portion of our business' exposure to changes in natural gas liquids (NGL) prices during 2004. We entered into financial swaps for 6,000 barrels per day for the period from August 2003 to September 2004. The average fixed price received is $0.47 per gallon for 2004 while we pay a monthly average floating price based on the Oil Pricing Information Service (OPIS) average price for each month. As of June 30, 2004 and December 31, 2003, the fair value of these cash flow hedges was a liability of $3.9 million and $3.3 million. For the quarter and six months ended June 30, 2004, we reclassified approximately $2.4 million and $4.6 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income to earnings. These reclassifications are included in our natural gas pipelines and plants segment. No ineffectiveness exists in this hedging relationship because all purchase and sales prices are based on the same index and volumes as the hedge transaction.

In connection with our GulfTerra Intrastate Alabama operations, we had fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2003 to offset the risk of increasing natural gas prices. For January and February 2004, we contracted to purchase 20,000 MMBtu and for March 2004, we contracted to purchase 15,000 MMBtu. The average fixed price paid during 2004 was $5.28 per MMBtu while we received a floating price based on the SONAT-Louisiana index (Southern Natural Pipeline index as published by the periodical "Inside FERC"). In March 2004, these cash flow hedges expired and we reclassified a gain of approximately $45 thousand from accumulated other comprehensive income to earnings. This reclassification is included in our natural gas pipelines and plants segment. No ineffectiveness existed in this hedging relationship because all purchase and sale prices were based on the same index and volumes as the hedge transaction.

In July 2003, to achieve a more balanced mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we paid the counterparty a LIBOR based interest rate plus a spread of 4.20% and received a fixed rate of 8½%. We accounted for this derivative as a fair value hedge under SFAS No. 133. In March 2004, we terminated our fixed to floating interest rate swap with our counterparty. The value of the transaction at termination was zero and as such neither we, nor our counterparty, were required to make any payments. Also, neither we, nor our counterparty, have any future obligations under this transaction.

The counterparties for our San Juan hedging activities are J. Aron and Company, an affiliate of Goldman Sachs, and UBS Warburg. We do not require collateral and do not anticipate non-performance by these counterparties. The counterparty for our NGL hedging activities is J. Aron and Company, an affiliate of Goldman Sachs, and we do not require collateral or anticipate non-performance by this counterparty.

11. BUSINESS SEGMENT INFORMATION

Each of our segments are business units that offer different services and products that are managed separately since each segment requires different technology and marketing strategies. We have segregated our business activities into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

We use performance cash flows (which we formerly referred to as EBITDA) to evaluate the performance of our segments, determine how resources will be allocated and develop strategic plans. We define performance cash flows as earnings before interest, depreciation and amortization and other adjustments. Historically our lenders and equity investors have viewed our performance cash flows measure as an indication of our ability to generate sufficient cash to meet debt obligations or to pay distributions. We believe that there has been a shift in investors' evaluation regarding investments in MLPs and they now put as much focus on the performance of an MLP investment as they do its ability to pay distributions. For that reason, we disclose performance cash flows as a measure of our segment performance.

We believe performance cash flows is also useful to our investors because it allows them to evaluate the effectiveness of our business segments from an operational perspective, exclusive of the costs to finance those activities and depreciation and amortization, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures.

The following are results as of and for the periods ended June 30:

	Natural Gas Pipelines and Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Non-Segment Activity[(1)]	Total
			(In thousands)			
Quarter Ended June 30, 2004						
Revenue from external customers	$ 182,990	$ 19,817	$ 11,743	$ 6,290	$ 4,378	$ 225,218
Intersegment revenue	31	—	—	579	(610)	—
Depreciation, depletion and amortization	18,163	2,513	2,880	1,395	1,129	26,080
Earnings from unconsolidated affiliates	584	1,379	—	1,295	—	3,258
Performance cash flows	83,904	13,252	7,721	5,816	N/A	N/A
Assets	2,344,760	464,228	317,211	175,161	84,721	3,386,081

	Natural Gas Pipelines and Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Non-Segment Activity[(1)]	Total
			(In thousands)			
Quarter Ended June 30, 2003						
Revenue from external customers[(2)]	$ 199,517	$ 16,009	$ 10,871	$ 6,101	$ 4,533	$ 237,031
Intersegment revenue	30	—	186	758	(974)	—
Depreciation, depletion and amortization	17,079	2,167	2,919	1,360	1,321	24,846
Earnings from unconsolidated affiliates	626	2,361	—	—	—	2,987
Performance cash flows	78,386	12,897	8,068	6,277	N/A	N/A
Assets	2,266,522	427,447	324,482	164,120	72,098	3,254,669
Six Months Ended June 30, 2004						
Revenue from external customers	$ 364,493	$ 35,005	$ 24,193	$ 12,932	$ 8,934	$ 445,557
Intersegment revenue	64	—	—	1,164	(1,228)	—
Depreciation, depletion and amortization	35,551	5,605	5,828	2,748	2,571	52,303
Earnings from unconsolidated affiliates	1,118	3,169	(30)	1,209	—	5,466
Performance cash flows	165,917	20,720	16,782	12,179	N/A	N/A
Assets	2,344,760	464,228	317,211	175,161	84,721	3,386,081
Six Months Ended June 30, 2003						
Revenue from external customers[(2)]	$ 396,706	$ 27,977	$ 22,477	$ 10,483	$ 9,483	$ 467,126
Intersegment revenue	68	—	278	1,404	(1,750)	—
Depreciation, depletion and amortization	33,632	4,364	5,881	2,560	2,106	48,543
Earnings from unconsolidated affiliates	1,255	5,048	—	—	—	6,303
Performance cash flows	156,221	24,497	15,069	10,512	N/A	N/A
Assets	2,266,522	427,447	324,482	164,120	72,098	3,254,669

(1) Represents predominantly our oil and natural gas production activities as well as intersegment eliminations. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Non-Segment Activity" column, to remove intersegment transactions.

(2) Revenue from external customers for our Oil and NGL Logistics segment has been reduced by $73.1 million and $121.9 million for the quarter and six months ended June 30, 2003 to reflect the revision of Typhoon Oil Pipeline's revenues and cost of natural gas and other products to conform to the current period presentation. See Note 1, Basis of Presentation and Summary of Significant Accounting Policies — Revenue Recognition and Cost of Natural Gas and Other Products.

A reconciliation of our segment performance cash flows to our net income is as follows:

	Quarter Ended June 30, 2004	Quarter Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands)			
Natural gas pipelines and plants	$ 83,904	$ 78,386	$165,917	$156,221
Oil and NGL logistics	13,252	12,897	20,720	24,497
Natural gas storage	7,721	8,068	16,782	15,069
Platform services	5,816	6,277	12,179	10,512
Segment performance cash flows	110,693	105,628	215,598	206,299
Plus: Other, nonsegment results	3,287	3,011	8,692	8,277
Earnings from unconsolidated affiliates	3,258	2,987	5,466	6,303
Cumulative effect of accounting change	—	—	—	1,690
Less: Interest and debt expense	26,696	31,838	54,727	66,324
Loss due to early redemptions of debt	16,285	—	16,285	3,762
Depreciation, depletion and amortization	26,080	24,846	52,303	48,543
Cash distributions from unconsolidated affiliates	700	3,520	1,450	8,230
Minority interest	—	47	(12)	80
Net cash payment received from El Paso Corporation	—	2,078	1,960	4,118
Net income	$ 47,477	$ 49,297	$103,043	$ 91,512

12. GUARANTOR FINANCIAL INFORMATION

As of June 30, 2004 and December 31, 2003, our credit facility is guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and is collateralized by substantially all of our assets. In addition, all of our senior notes and senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and each of our subsidiaries, excluding our unrestricted subsidiaries. Non-guarantor subsidiaries for the quarter and six months ended June 30, 2004, consisted of our unrestricted subsidiaries. Non-guarantor subsidiaries for the quarter and six months ended June 30, 2003, consisted of Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C., GulfTerra Arizona Gas, L.L.C., Cameron Highway Pipeline GP I, L.L.C., Cameron Highway Pipeline II, L.P., Cameron Highway Pipeline III, L.P., and Cameron Highway Oil Pipeline Company.

The following condensed consolidating financial statements are included so that separate financial statements of our guarantor subsidiaries are not required to be filed with the SEC. These condensed consolidating financial statements present our investments in both consolidated subsidiaries and unconsolidated affiliates using the equity method of accounting. The consolidating eliminations column on our condensed consolidating balance sheets below eliminates our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries. The consolidating eliminations column in our condensed consolidating statements of income and cash flows eliminates earnings from our consolidated affiliates.

Condensed Consolidating Statements of Income
For the Quarter Ended June 30, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$148	$225,070	$ —	$225,218
Operating expenses					
Cost of natural gas and other products	—	—	60,095	—	60,095
Operation and maintenance	—	74	51,893	—	51,967
Depreciation, depletion and amortization	36	—	26,044	—	26,080
	36	74	138,032	—	138,142
Operating income (loss)	(36)	74	87,038	—	87,076
Earnings from consolidated affiliates	74,501	—	—	(74,501)	—
Earnings from unconsolidated affiliates	—	—	3,258	—	3,258
Other income	39	—	85	—	124
Interest and debt expense	10,742	(6)	15,960	—	26,696
Loss due to early redemptions of debt	16,285	—	—	—	16,285
Net income	$47,477	$ 80	$ 74,421	$(74,501)	$ 47,477

Condensed Consolidating Statements of Income
For the Quarter Ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries[1]	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$229	$236,802	$ —	$237,031
Operating expenses					
Cost of natural gas and other products	—	—	85,385	—	85,385
Operation and maintenance	2,737	68	45,746	—	48,551
Depreciation, depletion and amortization	37	10	24,799	—	24,846
Loss on sale of long-lived assets	—	—	363	—	363
	2,774	78	156,293	—	159,145
Operating income (loss)	(2,774)	151	80,509	—	77,886
Earnings from consolidated affiliates	62,892	—	—	(62,892)	—
Earnings from unconsolidated affiliates	—	—	2,987	—	2,987
Minority interest expense	—	(47)	—	—	(47)
Other income	203	—	106	—	309
Interest and debt expense	11,024	—	20,814	—	31,838
Net income	$49,297	$104	$ 62,788	$(62,892)	$ 49,297

(1) Operating revenues and cost of natural gas and other products for our guarantor subsidiaries has been reduced by $73.1 million to reflect the revision of Typhoon Oil Pipeline's revenues and cost of natural gas and other products to conform to the current period presentation. See Note 1, Basis of Presentation and Summary of Significant Accounting Policies — Revenue Recognition and Cost of Natural Gas and Other Products.

Condensed Consolidating Statements of Income
For the Six Months Ended June 30, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$282	$445,275	$ —	$445,557
Operating expenses					
Cost of natural gas and other products	—	—	124,522	—	124,522
Operation and maintenance	—	137	100,326	—	100,463
Depreciation, depletion and amortization	72	—	52,231	—	52,303
Gain on sale of long-lived assets	—	—	(24)	—	(24)
	72	137	277,055	—	277,264
Operating income (loss)	(72)	145	168,220	—	168,293
Earnings from consolidated affiliates	140,335	—	—	(140,335)	—
Earnings (loss) from unconsolidated affiliates	—	(30)	5,496	—	5,466
Minority interest income	—	12	—	—	12
Other income	112	—	172	—	284
Interest and debt expense	21,047	(13)	33,693	—	54,727
Loss due to early redemptions of debt	16,285	—	—	—	16,285
Net income	$103,043	$140	$140,195	$(140,335)	$103,043

Condensed Consolidating Statements of Income
For the Six Months Ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries[(1)]	Consolidating Eliminations	Consolidated Total
		(In thousands)			
Operating revenues	$ —	$506	$466,620	$ —	$467,126
Operating expenses					
Cost of natural gas and other products	—	—	176,138	—	176,138
Operation and maintenance	3,204	142	85,849	—	89,195
Depreciation, depletion and amortization	74	21	48,448	—	48,543
Loss on sale of long-lived assets	—	—	257	—	257
	3,278	163	310,692	—	314,133
Operating income (loss)	(3,278)	343	155,928	—	152,993
Earnings from consolidated affiliates	124,397	—	—	(124,397)	—
Earnings from unconsolidated affiliates	—	—	6,303	—	6,303
Minority interest expense	—	(80)	—	—	(80)
Other income	451	—	241	—	692
Interest and debt expense	26,296	—	40,028	—	66,324
Loss due to early redemptions of debt	3,762	—	—	—	3,762
Income before cumulative effect of accounting change	91,512	263	122,444	(124,397)	89,822
Cumulative effect of accounting change	—	—	1,690	—	1,690
Net income	$ 91,512	$263	$124,134	$(124,397)	$ 91,512

(1) Operating revenues and cost of natural gas and other products for our guarantor subsidiaries has been reduced by $121.9 million to reflect the revision of Typhoon Oil Pipeline's revenues and cost of natural gas and other products to conform to the current period presentation. See Note 1, Basis of Presentation and Summary of Significant Accounting Policies — Revenue Recognition and Cost of Natural Gas and Other Products.

Condensed Consolidating Balance Sheets
June 30, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 33,445	$ —	$ —	$ —	$ 33,445
Accounts receivable, net					
Trade	—	83	123,348	—	123,431
Affiliates	699,096	267	32,348	(693,728)	37,983
Affiliated note receivable	—	3,713	—	—	3,713
Other current assets	4,022	—	17,648	—	21,670
Total current assets	736,563	4,063	173,344	(693,728)	220,242
Property, plant and equipment, net	9,161	431	2,920,413	—	2,930,005
Intangible assets	—	—	3,177	—	3,177
Investment in unconsolidated affiliates	—	—	203,303	—	203,303
Investment in consolidated affiliates	2,246,481	—	781	(2,247,262)	—
Other noncurrent assets	193,574	—	5,779	(169,999)	29,354
Total assets	$3,185,779	$4,494	$3,306,797	$(3,110,989)	$3,386,081
Current liabilities					
Accounts payable					
Trade	$ —	$ —	$ 124,466	$ —	$ 124,466
Affiliates	26,924	—	691,257	(693,728)	24,453
Accrued interest	8,083	—	—	—	8,083
Current maturities of senior secured term loans	5,000	—	—	—	5,000
Other current liabilities	6,911	—	34,417	—	41,328
Total current liabilities	46,918	—	850,140	(693,728)	203,330
Revolving credit facility	462,000	—	—	—	462,000
Senior secured term loans, less current maturities	493,500	—	—	—	493,500
Long-term debt	923,016	—	—	—	923,016
Other noncurrent liabilities	—	—	212,088	(169,999)	42,089
Minority interest	—	1,801	—	—	1,801
Partners' capital	1,260,345	2,693	2,244,569	(2,247,262)	1,260,345
Total liabilities and partners' capital	$3,185,779	$4,494	$3,306,797	$(3,110,989)	$3,386,081

Condensed Consolidating Balance Sheets
December 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 30,425	$ —	$ —	$ —	$ 30,425
Accounts receivable, net					
Trade	—	113	106,157	—	106,270
Affiliates	746,126	3,541	41,606	(743,308)	47,965
Affiliated note receivable	—	3,713	55	—	3,768
Other current assets	3,573	—	17,022	—	20,595
Total current assets	780,124	7,367	164,840	(743,308)	209,023
Property, plant and equipment, net	8,039	431	2,886,022	—	2,894,492
Intangible assets	—	—	3,401	—	3,401
Investment in unconsolidated affiliates	—	—	175,747	—	175,747
Investment in consolidated affiliates	2,108,104	—	622	(2,108,726)	—
Other noncurrent assets	199,761	—	9,155	(169,999)	38,917
Total assets	$3,096,028	$7,798	$3,239,787	$(3,022,033)	$3,321,580
Current liabilities					
Accounts payable					
Trade	$ —	$ 22	$ 129,241	$ —	$ 129,263
Affiliates	10,691	3,499	767,988	(743,308)	38,870
Accrued interest	10,930	—	269	—	11,199
Current maturities of senior secured term loan	3,000	—	—	—	3,000
Other current liabilities	2,601	1	24,433	—	27,035
Total current liabilities	27,222	3,522	921,931	(743,308)	209,367
Revolving credit facility	382,000	—	—	—	382,000
Senior secured term loan, less current maturities	297,000	—	—	—	297,000
Long-term debt	1,129,807	—	—	—	1,129,807
Other noncurrent liabilities	7,413	—	211,629	(169,999)	49,043
Minority interest	—	1,777	—	—	1,777
Partners' capital	1,252,586	2,499	2,106,227	(2,108,726)	1,252,586
Total liabilities and partners' capital	$3,096,028	$7,798	$3,239,787	$(3,022,033)	$3,321,580

Condensed Consolidating Statements of Cash Flows
For the Six Months Ended June 30, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 103,043	$ 140	$ 140,195	$(140,335)	$ 103,043
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	72	—	52,231	—	52,303
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	30	(5,496)	—	(5,466)
Distributions from unconsolidated affiliates	—	—	1,450	—	1,450
Gain on sale of long-lived assets	—	—	(24)	—	(24)
Loss due to write-off of unamortized debt issuance costs	3,884	—	—	—	3,884
Amortization of debt issuance costs, premiums and discounts	2,651	—	—	—	2,651
Other noncash items	1,204	24	5,124	—	6,352
Working capital changes, net of acquisitions and noncash transactions	17,564	(75)	(45,450)	—	(27,961)
Net cash provided by operating activities	128,418	119	148,030	(140,335)	136,232
Cash flows from investing activities					
Additions to property, plant and equipment	(1,194)	—	(84,913)	—	(86,107)
Proceeds from sale and retirement of assets	—	—	197	—	197
Additions to investments in unconsolidated affiliates	—	—	(17,947)	—	(17,947)
Net cash used in investing activities	(1,194)	—	(102,663)	—	(103,857)
Cash flows from financing activities					
Net proceeds from revolving credit facility	386,932	—	—	—	386,932
Repayments of revolving credit facility	(307,000)	—	—	—	(307,000)
Net proceeds from senior secured term loan	199,651	—	—	—	199,651
Repayment of senior secured term loan	(1,500)	—	—	—	(1,500)
Debt issuance costs for issuance of long-term debt	(52)	—	—	—	(52)
Repayments of long-term debt	(214,085)	—	—	—	(214,085)
Net proceeds from issuance of common units and conversion of Series F convertible units	48,536	—	—	—	48,536
Advances with affiliates	(94,849)	(119)	(45,367)	140,335	—
Distributions to partners	(142,317)	—	—	—	(142,317)
Contribution from general partner	480	—	—	—	480
Net cash used in financing activities	(124,204)	(119)	(45,367)	140,335	(29,355)
Increase in cash and cash equivalents	$ 3,020	$ —	$ —	$ —	3,020
Cash and cash equivalents at beginning of period					30,425
Cash and cash equivalents at end of period					$ 33,445

Condensed Consolidating Statements of Cash Flows
For the Six Months Ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 91,512	$ 263	$ 124,134	$(124,397)	$ 91,512
Less cumulative effect of accounting change	—	—	1,690	—	1,690
Income before cumulative effect of accounting change	91,512	263	122,444	(124,397)	89,822
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	74	21	48,448	—	48,543
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(6,303)	—	(6,303)
Distributions from unconsolidated affiliates	—	—	8,230	—	8,230
Loss on sale of long-lived assets	—	—	257	—	257
Loss due to write-off of unamortized debt issuance costs	3,762	—	—	—	3,762
Amortization of debt issuance costs, premiums and discounts	3,694	—	322	—	4,016
Other noncash items	592	310	439	—	1,341
Working capital changes, net of acquisitions and noncash transactions	15,333	(546)	(30,289)	—	(15,502)
Net cash provided by operating activities	114,967	48	143,548	(124,397)	134,166
Cash flows from investing activities					
Additions to property, plant and equipment	(584)	(19)	(206,408)	—	(207,011)
Proceeds from sale and retirement of assets	—	—	3,215	—	3,215
Additions to investments in unconsolidated affiliates	—	(197)	—	—	(197)
Net cash used in investing activities	(584)	(216)	(203,193)	—	(203,993)
Cash flows from financing activities					
Net proceeds from revolving credit facility	223,000	—	—	—	223,000
Repayments of revolving credit facility	(298,854)	—	—	—	(298,854)
Repayment of senior secured term loan	(2,500)	—	—	—	(2,500)
Repayment of senior secured acquisition term loan	(237,500)	—	—	—	(237,500)
Net proceeds from issuance of long-term debt	292,479	—	—	—	292,479
Net proceeds from issuance of common units and Series F convertible units	182,182	—	—	—	182,182
Advances with affiliates	(177,653)	168	53,088	124,397	—
Distributions to partners	(107,427)	—	—	—	(107,427)
Contribution from general partner	1	—	—	—	1
Net cash provided by (used in) financing activities	(126,272)	168	53,088	124,397	51,381
Decrease in cash and cash equivalents	$ (11,889)	$ —	$ (6,557)	$ —	(18,446)
Cash and cash equivalents at beginning of period					36,099
Cash and cash equivalents at end of period					$ 17,653
Schedule of noncash financing activities:					
Redemption of Series B preference units contributed from our general partner	$ 1,788	$ —	$ —	$ —	$ 1,788

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in Part II, Items 7, 7A and 8, in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2003, in addition to the interim financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

We have experienced substantial growth over the last several years through a series of large strategic acquisitions including our San Juan gathering and processing system in New Mexico and our Texas intrastate gas gathering and transmission system, both of which were purchased from El Paso Corporation in 2002. In the future, we expect to continue our growth strategy from our significant portfolio of organic development projects located in the Gulf of Mexico, which are slated to be completed in the second half of 2004 to 2006 time period. This expansion strategy started with a first generation of offshore projects initiated by us in the mid to late 1990s. These projects included the acquisition and construction of oil and natural gas pipelines and hub platforms situated along the edge of the outer continental shelf (OCS) to serve discoveries beyond the OCS. Subsequently, we developed a second generation of projects which consisted of interconnecting GulfTerra-owned and producer-owned gathering systems to our OCS pipeline headers and hub platforms, giving us a competitive reach into the prolific areas of development in the deepwater trend. In recent years, we have moved into a third stage of offshore infrastructure projects which consist of interconnecting our earlier generation offshore assets through the construction of deepwater pipeline extensions to newly installed GulfTerra-owned and producer-owned deepwater hub platforms. These third generation projects, which are anchored by major discoveries in the deepwater area, are expected to create a seamless infrastructure which should accelerate the development of satellite fields and competitively position us for the next generation of deeper discoveries.

During the second quarter of 2004, we completed the installation of our Marco Polo oil and natural gas pipelines, and we began receiving first production on our 50 percent owned Marco Polo TLP in July 2004. Additionally, in July 2004, we received first production from the Red Hawk field through our recently completed Phoenix gathering system. Further, during the quarter we reached agreement to build another pipeline project in the deepwater Gulf of Mexico to provide oil and natural gas gathering services from the Ticonderoga and Constitution fields, which are 100 percent owned by Kerr-McGee Oil & Gas Corporation (Kerr-McGee), a wholly owned affiliate of Kerr-McGee Corporation. First production from this project is scheduled for the first half of 2006 and is dedicated to our 50 percent owned Cameron Highway oil pipeline system which is nearing completion.

Merger with Enterprise

On December 15, 2003, we, along with Enterprise and El Paso Corporation, announced that we had executed definitive agreements to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs.

In April 2004, Enterprise and El Paso Corporation amended their agreement with respect to the ownership of Enterprise's general partner interest upon the completion of our merger with Enterprise.

As originally envisioned in the merger agreement, El Paso Corporation was to contribute its 50-percent ownership interest in our general partner to Enterprise's general partner, in exchange for a 50-percent ownership interest in Enterprise's general partner. Under the amended transaction, El Paso Corporation will still contribute its 50-percent ownership interest in our general partner to Enterprise's general partner, but in exchange, El Paso Corporation will receive a 9.9 percent ownership interest in Enterprise's general partner and $370 million in cash. The remaining 90.1 percent ownership interest in Enterprise's general partner will continue to be owned by affiliates of privately-held Enterprise Products Company.

The remaining transactions with respect to our merger with Enterprise are unchanged. These include:

- the payment of $500 million in cash from Enterprise to El Paso Corporation for approximately 13.8 million units, which include 2.9 million of our common units and all of our Series C units owned by El Paso Corporation; and
- the exchange of 1.81 Enterprise common units for each GulfTerra common unit owned by GulfTerra's unitholders, including the remaining approximately 7.5 million GulfTerra common units owned by El Paso Corporation.

On June 22, 2004, Enterprise's registration statement on Form S-4 was declared effective by the SEC. On July 29, 2004, our common and Series C unitholders approved the adoption of the merger agreement to combine us with a wholly-owned subsidiary of Enterprise. See Part II, Other Information, Item 4. Submission of Matters to a Vote of Security Holders, for the results of the unitholder vote. We expect the completion of the merger to occur in the third quarter of 2004, although it remains subject to review by the FTC and the satisfaction of other conditions to close.

Merger-Related Costs

As a result of the pending merger with Enterprise, we determined that it was in our and our unitholders' best interest to offer selected employees of El Paso Corporation incentives to continue to focus on the business of the partnership during the merger process. We have accounted for these incentives under the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* In March 2004, we recorded a liability and a related deferred charge of $4.3 million, which was reflected in other current liabilities and other current assets on our balance sheets. Our liability was estimated based upon the number of employees accepting the offer and the discounted amount they are expected to be paid. We are amortizing the deferred charge to expense ratably over the expected period of the services required in order to qualify for receiving the payments. We expect to amortize the entire expense by merger close. During the quarter and six months ended June 30, 2004, we amortized $2.2 million and $2.8 million to expense. As of June 30, 2004, the remaining deferred charge was $1.5 million. If our expectations of future amounts to be paid or the period of service to be rendered change, we will adjust our liability.

Additionally, during the first quarter of 2004, we recognized an expense of $3.5 million associated with a fairness opinion we received on our pending merger with Enterprise. During the quarter and six months ended June 30, 2004, we recognized expenses for legal and audit fees totaling $1.4 million and $1.5 million associated with our pending merger with Enterprise. We expect to incur additional merger-related costs prior to the actual date of the merger including incremental legal, audit and advisory fees. All of our merger-related costs are included in operation and maintenance expenses on our statements of income and are allocated across all of our operating segments.

Under the merger agreement with Enterprise, we are obligated to repurchase, at reasonable prices, before the effective time of the merger, all outstanding employee and director unit options that have not been exercised or otherwise canceled. Approximately 1,000,000 common unit options were outstanding at June 30, 2004, held by 28 current and former employees and directors. Since we do not have the right under our option plan to force our option holders to sell their options, we were required to negotiate a separate option purchase agreement individually with each option holder. The governance and compensation committee of our general partner's board of directors engaged an independent financial advisor to assist in the determination of the appropriate repurchase prices for the outstanding options. Subsequent to June 30, 2004, we entered into option purchase agreements with all the option holders under which we have agreed to purchase for cash and/or common units, and the option holders have agreed to sell, any options that remain outstanding on the merger closing date for a negotiated price. Each option purchase agreement permits the option holder to exercise any or all of his or her options at any time and from time to time prior to the merger closing. Based on information provided by the financial advisor engaged by the governance and compensation committee, we estimate that the value, in the aggregate, of the outstanding options to be repurchased is approximately $13 million.

Liquidity and Capital Resources

Our principal requirements for cash, other than our routine operating costs, are for capital expenditures, debt service, business acquisitions and distributions to our partners. We plan to fund our short-term cash needs, including operating costs, maintenance capital expenditures and cash distributions to our partners, from cash generated from our operating activities and borrowings under our credit facility. Capital expenditures we expect to benefit us over longer time periods, including our organic growth projects and business acquisitions, we plan to fund through a variety of sources (either separately or in combination), which include issuing additional common units, borrowing under commercial bank credit facilities, issuing public or private placement debt and other financing transactions. We plan to fund our debt service requirements through a combination of refinancing arrangements and cash generated from our operating activities. Our merger agreement with Enterprise limits our ability to raise additional capital and incur additional indebtedness prior to the closing of the merger without Enterprise's approval; however, we believe that these limitations will not affect our liquidity.

Capital Resources

Series F Convertible Units

In connection with a public offering in May 2003, we issued 80 Series F convertible units convertible into a maximum of 8,329,679 common units and comprised of two separate detachable units. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until the date we merge with Enterprise (subject to other defined extension rights). The Series F2 units are convertible into up to $40 million of common units prior to March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser (i) of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75, or (ii) the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units, (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven business days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units, assuming we had received a conversion notice on June 30, 2004 and August 5, 2004, was $38.47 and $37.10 per common unit. Holders of Series F convertible units are not entitled to vote or to receive distributions. The value of the Series F convertible units was $2.6 million as of June 30, 2004, and is included in partners' capital as a component of common units capital.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at June 30, 2004 and December 31, 2003.

In July 2004, 10 Series F1 convertible units were converted into 261,437 common units, for which the holder of the convertible units paid us $10 million. Additionally, our general partner contributed to us $0.1 million in cash in order to maintain its one percent general partner interest.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million. Additionally, our general partner contributed to us $0.4 million in cash in order to maintain its one percent general partner interest.

Any Series F1 convertible units for which a conversion notice has not been delivered prior to the merger closing date, or termination of the merger, will expire upon the closing, or termination, of the merger with Enterprise. Any Series F2 convertible units outstanding at the merger date will be converted into rights to receive Enterprise common units, subject to the restrictions governing the Series F units. The number of Enterprise common units and the price per unit at conversion will be adjusted based on the 1.81 exchange ratio.

Indebtedness and Other Obligations

In April 2004, we redeemed, at a premium, approximately $39.1 million in principal amount of our 8½% senior subordinated notes due June 2010. We used the proceeds from the conversion of our Series F1 convertible units to fund this redemption. In connection with the redemption of the notes, we recognized additional expense during the quarter ended June 30, 2004, totaling $4.1 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs. We accounted for these costs as an expense in accordance with the provisions of SFAS No. 145.

In May 2004, we obtained an additional $200 million senior secured term loan which we initially used to temporarily reduce indebtedness under our $700 million revolving credit facility and subsequently to fund the redemption of our $175 million aggregate principal amount of 10⅜% senior subordinated notes due 2009. The new senior secured term loan is payable in semi-annual installments of $1.0 million in November and May of each year for the first six installments, and the remaining balance is due at maturity in October 2007. We may elect that all or a portion of the senior secured term loan bear interest at either 1.25% over the variable base rate (described in Item 1, Financial Statements, Note 4) or LIBOR increased by 2.25%.

In June 2004, we redeemed all of our outstanding $175 million aggregate principal amount of 10⅜% senior subordinated notes due 2009. The notes were redeemed at a redemption price of 105.2% of the principal amount, plus accrued and unpaid interest up to June 1, 2004. To fund this redemption, we used the proceeds from our additional $200 million senior secured term loan obtained in May 2004. This additional amount was initially used to temporarily reduce indebtedness under our revolving credit facility. In connection with the redemption of the notes, we recognized additional expense during the quarter ended June 30, 2004, totaling $12.2 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs. We accounted for these costs as an expense in accordance with the provisions of SFAS No. 145.

See Item 1., Financial Statements, Note 4, for additional discussion of our debt obligations.

The following table presents the timing and amounts of our debt repayment and other obligations for the years following June 30, 2004, that we believe could affect our liquidity (in millions):

Debt Repayment and Other Obligations	<1 Year	1-3 Years	3-5 Years	After 5 Years	Total
Revolving credit facility	$ —	$462	$ —	$ —	$ 462
Senior secured term loans	5	10	484	—	499
6¼% senior notes issued July 2003, due June 2010	—	—	—	250	250
8½% senior subordinated notes issued March 2003, due June 2010	—	—	—	216	216
8½% senior subordinated notes issued May 2001, due June 2011	—	—	—	168	168
8½% senior subordinated notes issued May 2002, due June 2011	—	—	—	154	154
10⅝% senior subordinated notes issued November 2002, due December 2012	—	—	—	134	134
Interest payable[(1)]	108	207	167	139	621
Wilson natural gas storage facility operating lease	5	10	5	—	20
Texas leased NGL storage facilities	2	2	1	2	7
Total debt repayment and other obligations	$120	$691	$657	$1,063	$2,531

(1) Interest payable is forecasted based on the notional fixed rate for our fixed rate securities and based on the June 30, 2004 variable rate for our variable rate securities.

The close of the merger will constitute a change of control, and thus a default, under our credit facility. To avoid a default, our credit facility must be refinanced or amended at or before the closing of the merger. Enterprise has stated that it currently intends that our credit facility be refinanced before the closing of the merger and that, if that does not occur, there are reasonable grounds to believe that our existing credit facility will be amended prior to the closing of the merger. If the facility is not amended or refinanced prior to closing, the resulting default would have a material adverse effect on the combined company. In addition, the closing of the merger will constitute a change of control under our indentures, and we will be required to offer to repurchase our outstanding senior subordinated notes (and possibly our senior notes) at 101 percent of their principal amount after the close. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the closing of the merger. On August 4, 2004, Enterprise announced that one of its subsidiaries commenced cash tender offers to purchase any and all of our outstanding senior subordinated and senior notes. In connection with the tender offers, Enterprise is soliciting consents to proposed amendments that would eliminate certain restrictive covenants and default provisions contained in the indentures governing the notes. Enterprise is commencing the tender offers and consent solicitations in anticipation of completing the merger, and the merger is a non-waivable condition to the completion of the tender offers and consent solicitations. We and Enterprise can agree on the date of the merger closing after the receipt of all necessary approvals. We do not intend to close until appropriate financing or other arrangements are in place.

Industrial Development Revenue Bonds

In April 2004, we reduced the sales tax assessable by the State of Mississippi related to our Petal natural gas storage expansion and pipeline project completed in September 2002 by completing that project's qualification for tax incentives available under the MBFA. To complete the qualification, Petal, our indirect, wholly-owned subsidiary, borrowed $52 million from the MBFC pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52 million in Industrial Development Revenue Bonds to GulfTerra Field Services, L.L.C., our direct, wholly-owned subsidiary. The loan agreement and the Industrial Development Revenue Bonds have identical interest rates of 6.25% and maturities of fifteen years. The bonds and tax exemptions are authorized under the MBFA. Petal may repay the loan agreement without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $0.6 million on our balance sheet as of June 30, 2004. We have also netted the interest expense and interest income amount of $0.6 million on our income statements for the quarter and six months ended June 30, 2004. Our presentation of the Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, *Offsetting of Amounts Related to Certain Contracts,* and SFAS No. 140, *Accounting for Transfers and Services of Financial Assets and Extinguishments of Liabilities,* since we have the ability and intent to offset these items.

Capital Expenditures

The ability to execute our growth strategy and complete our projects is dependent upon our access to the capital necessary to fund projects and acquisitions. Our success with capital raising efforts, including the formation of joint ventures to share costs and risks, continues to be the critical factor which determines how much we actually spend. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs and, although we currently intend to make the forecasted expenditures discussed below, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in the capital markets.

Under the merger agreement with Enterprise, we cannot make capital expenditures, without Enterprise's consent, in excess of $5 million individually or $25 million in the aggregate other than (1) as required on an emergency basis and (2) those planned expenditures previously disclosed to Enterprise. The forecasted expenditures disclosed in the tables below were either consented to by Enterprise, planned expenditures previously disclosed to Enterprise or expenditures which fall within the monetary thresholds in the merger agreement.

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to provide capital from operating cash flows or otherwise obtain the capital necessary to accomplish our operating and growth objectives. These estimates may change due to factors beyond our control, such as weather related issues, changes in supplier prices or poor economic conditions. Further, estimates may change as a result of decisions made at a later date, which may include acquisitions, scope changes or decisions to take on additional partners. Our projection of expenditures for the quarters ended June 30 and March 31, 2004 as presented in our 2003 Annual Report on Form 10-K, as amended, was $41 million and $76 million; however, our actual expenditures were approximately $38 million and $48 million.

The table below depicts our estimate of projects and capital maintenance expenditures through June 30, 2005. These estimates are net of anticipated contributions in aid of construction and contributions from joint venture partners. We expect to be able to fund these forecasted expenditures from the combination of operating cash flow and funds available under our revolving credit facility and other financing arrangements. Actual results may vary from these projections. We do not disclose planned expenditures related to our offshore projects unless we have entered into definitive agreements.

Forecasted Expenditures

	Quarters Ending				Net Total Forecasted Expenditures
	September 30, 2004	December 31, 2004	March 31, 2005	June 30, 2005	
	(In millions)				
Net Forecasted Capital Project Expenditures	$39	$54	$75	$18	$186
Other Forecasted Capital Expenditures[1]	10	5	10	10	35
Additional Capital Contributions to Our Unconsolidated Affiliates	13	—	—	—	13
Total Forecasted Expenditures	$62	$59	$85	$28	$234

(1) We do not plan to make any significant capital expenditures for environmental matters within the next twelve months.

Construction Projects

	Capital Expenditures				Capacity		
	Forecasted		As of June 30, 2004				
	Total[1]	GulfTerra[2]	Total[1]	GulfTerra[2]	Oil	Natural Gas	Expected In-Service
	(In millions)				(MBbls/d)	(MMcf/d)	
Wholly owned projects							
Marco Polo Natural Gas and Oil Pipelines	$114	$ 96	$110	$93	120	400	July 2004
Phoenix Gathering System	65	59	60	57	—	450	July 2004
Petal Conversion Project	17	17	—	—	—	1.8[3]	Fourth Quarter 2004
Constitution Gathering System	120	120	1	1	80	200	First Half of 2006
Joint venture project							
Cameron Highway Oil Pipeline	474	95	412	85	500	—	Fourth Quarter 2004

(1) Includes 100 percent of costs and is not reduced for anticipated contributions in aid of construction, project financings and contributions from joint venture partners. We expect to receive $6.1 million (of which $3.0 million has been collected as of June 30, 2004) from ANR Pipeline Company for our Phoenix gathering system, which went into service in July 2004. We expect to receive the remaining $3.1 million from ANR Pipeline Company in the third quarter of 2004. We have received $10.5 million from ANR Pipeline Company and $7.0 million from El Paso Field Services for the Marco Polo natural gas pipeline, which went into service in July 2004.

(2) GulfTerra expenditures are net of anticipated or received contributions in aid of construction, project financings and contributions from joint venture partners, to the extent applicable.

(3) Capacity in Bcf

Petal Conversion Project

We are planning, subject to final regulatory approval, to convert our existing brine well at our propane storage caverns in Hattiesburg, Mississippi to natural gas service. This conversion will cost approximately $17 million and will create a new 1.8 Bcf working natural gas cavern that would be integrated into our Petal natural gas storage facility. We expect to have the cavern in service during the fourth quarter of 2004. In the second quarter of 2004 , Petal executed agreements with BP Energy Company for the 1.8 Bcf of firm storage capacity in the new natural gas cavern. The agreement is for a five-year term and is anticipated to commence in October 2004. This commitment increases BP's position at Petal to 3.45 Bcf. We expect to fund the conversion project costs through internally generated funds and borrowings under our credit facility.

Constitution Gathering System

In July 2004, we announced we had entered into a definitive agreement to construct, own, and operate oil and natural gas pipelines to provide firm gathering services from the Constitution field, which is 100 percent owned by Kerr-McGee. The Constitution field is located in 5,300 feet of water in Green Canyon Blocks 679 and 680 in the Central Gulf of Mexico. The new 32-mile, 16-inch natural gas pipeline will have a capacity of up to 200 MMcf/d and will connect to our existing Anaconda Gathering System (the combination of our Marco Polo natural gas pipeline and our Typhoon natural gas pipeline). The new oil pipeline will be a 70-mile, 16-inch line with a minimum capacity of 80 MBbls/d that will connect with the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline systems at the new Ship Shoal 332B platform. We plan to install the new pipelines in the summer of 2005, with first production scheduled for the first half of 2006. Kerr-McGee has dedicated production from its Constitution and Ticonderoga discoveries, as well as future potential production from several undeveloped blocks in the area, for gathering on our new oil and natural gas pipelines. We expect to fund this construction project through internally generated funds and borrowings under our credit facility.

Cash From Operating Activities

Net cash provided by operating activities was $136.2 million for the six months ended June 30, 2004, compared to $134.2 million for the same period in 2003. This increase was primarily attributable to higher operating cash flows generated by our Texas intrastate pipeline system, NGL pipeline systems, and Falcon Nest platform. This increase was partially offset by lower distributions from our unconsolidated affiliate, Poseidon, as Poseidon began withholding distributions to fund its capital expenditures related to its Front Runner oil pipeline.

Cash Used In Investing Activities

Net cash used in investing activities was approximately $103.9 million for the six months ended June 30, 2004. Our investing activities included capital expenditures of $86.1 million primarily related to our Marco Polo pipelines, Phoenix gathering system and the San Juan optimization project, as well as maintenance expenditures related to our Chaco plant, San Juan gathering system, Texas Intrastate system and our NGL pipeline systems. Our investing activities also included additions to investments in unconsolidated affiliates of $17.9 million, of which $14.2 million related to additional equity contributions we made to Deepwater Gateway for the construction of the Marco Polo TLP and $3.7 million related to the capitalization of interest associated with our equity investments in Deepwater Gateway and Cameron Highway.

Cash Used in Financing Activities

Net cash used in financing activities was approximately $29.4 million for the six months ended June 30, 2004. During 2004, cash used in our financing activities included repayments on our revolving credit facility, repayments of our long-term debt and distributions to our partners. Cash provided by financing activities included the proceeds received from the conversion of Series F1 convertible units into common units, the proceeds received from the exercise of unit options, the proceeds received from our additional senior secured term loan and the proceeds from borrowings under our revolving credit facility.

Results of Operations

Our business activities are segregated into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. For a further discussion of the individual segments, see Item 1., Financial Statements, Note 11. For the past two years, inflation has not had a material effect on any of our financial results.

Segment Results

We use performance cash flows (which we formerly referred to as EBITDA) to evaluate the performance of our segments, determine how resources will be allocated and develop strategic plans. We define performance cash flows as earnings before interest, depreciation and amortization and other adjustments. Historically our lenders and equity investors have viewed our performance cash flows measure as an indication of our ability to generate sufficient cash to meet debt obligations or to pay distributions. We believe that there has been a shift in investors' evaluation regarding investments in MLPs and they now put as much focus on the performance of an MLP investment as they do its ability to pay distributions. For that reason, we disclose performance cash flows as a measure of our segment performance.

We believe performance cash flows is also useful to our investors because it allows them to evaluate the effectiveness of our business segments from an operational perspective, exclusive of the costs to finance those activities and depreciation and amortization, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures.

A reconciliation of our segment performance cash flows to our net income is as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands)			
Natural gas pipelines and plants	$ 83,904	$ 78,386	$165,917	$156,221
Oil and NGL logistics	13,252	12,897	20,720	24,497
Natural gas storage	7,721	8,068	16,782	15,069
Platform services	5,816	6,277	12,179	10,512
Segment performance cash flows	110,693	105,628	215,598	206,299
Plus: Other, nonsegment results	3,287	3,011	8,692	8,277
Earnings from unconsolidated affiliates	3,258	2,987	5,466	6,303
Cumulative effect of accounting change	—	—	—	1,690
Less: Interest and debt expense	26,696	31,838	54,727	66,324
Loss due to early redemptions of debt	16,285	—	16,285	3,762
Depreciation, depletion and amortization	26,080	24,846	52,303	48,543
Cash distributions from unconsolidated affiliates	700	3,520	1,450	8,230
Minority interest	—	47	(12)	80
Net cash payment received from El Paso Corporation	—	2,078	1,960	4,118
Net income	$ 47,477	$ 49,297	$103,043	$ 91,512

Natural Gas Pipelines and Plants

	Quarter Ended June 30, 2004	Quarter Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands, except for volumes)			
Natural gas pipelines and plants revenue	$183,021	$199,547	$ 364,557	$ 396,774
Cost of natural gas and other products	(59,914)	(86,123)	(123,860)	(175,919)
Natural gas pipelines and plants margin	123,107	113,424	240,697	220,855
Operating expenses excluding depreciation, depletion, and amortization	(39,990)	(36,123)	(76,404)	(66,569)
Other income and cash distributions from unconsolidated affiliates in excess of earnings[1]	787	1,038	1,624	1,855
Minority interest	—	47	—	80
Performance cash flows	$ 83,904	$ 78,386	$ 165,917	$ 156,221
Volumes (MDth/d)				
Texas Intrastate	3,298	3,407	3,254	3,380
San Juan Gathering	1,255	1,241	1,251	1,186
Permian Basin Gathering	312	349	303	334
HIOS	815	707	779	729
Falcon Nest Pipeline[2]	280	197	276	114
Viosca Knoll Gathering	658	672	649	680
Other natural gas pipelines	593	470	558	493
Processing plants	739	781	730	796
Total volumes	7,950	7,824	7,800	7,712

(1) Earnings from unconsolidated affiliates for the quarters ended June 30, 2004 and 2003, were $584 thousand and $626 thousand. Earnings from unconsolidated affiliates for the six months ended June 30, 2004 and 2003, were $1,118 thousand and $1,255 thousand.

(2) The Falcon Nest pipeline was placed in service in March 2003.

We provide natural gas gathering and transportation services for a fee. Agreements with some customers of our pipelines and plants require that we purchase natural gas from them at the wellhead for an index price less an amount that compensates us for gathering services, after which we sell the natural gas into the open market at points on our system at the same index price. Accordingly, under these agreements, our operating revenues and costs of natural gas and other products are impacted equally by changes in energy commodity prices, thus our margin for these agreements reflects only the fee we received for gathering services. At our Indian Basin processing facility, our revenues reflect the gross sales of NGL attributable to our ownership percentage. Included in our cost of natural gas and other products is the payment to the producers for the NGL we marketed on their behalf. For these reasons, we feel that gross margin (revenue less cost of natural gas and other products) provides a more accurate and meaningful basis for analyzing operating results for this segment.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. This was primarily associated with an unexplained increase in our fuel use which was not contemporaneously collected from our customers. We initially believed a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October 2002. We conducted a thorough review of our operations and were unable to determine the exact cause of the increase in fuel use. The fuel use has since returned to historical levels. As of June 30, 2004, we have recorded gross fuel differences of approximately $7.5 million, which we included in other non-current assets on our balance sheet. In the future, we expect to have an opportunity to file for collection of the fuel differences. However, at this time we are not able to determine what amount, if any, may be collectible from our customers. Any amounts we are unable to resolve or collect from our customers will negatively impact the future results of our natural gas pipelines and plants segment.

In July 2004, we completed a number of our natural gas pipeline construction projects including the Marco Polo natural gas pipeline and the Phoenix gathering system (described below). As a result of these natural gas pipeline systems being placed into service, we now own interests in natural gas pipeline systems with a combined maximum design capacity (net to our interest) of over 11.8 Bcf/d of natural gas, up from 10.9 Bcf/d. Additionally, we expect an increase in transportation revenues in the second half of 2004 derived from producer transportation on these systems.

Marco Polo Natural Gas Pipeline

In July 2004, we completed construction on our 75-mile, 18-inch to 20-inch natural gas pipeline that supports the Marco Polo TLP. The Marco Polo natural gas pipeline has a capacity of 400 MMcf/d and interconnects with our Typhoon natural gas pipeline in Green Canyon Block 236.

Phoenix Gathering System

In July 2004, we completed construction on our 78-mile, 18-inch natural gas gathering system. The Phoenix gathering system has a capacity of 450 MMcf/d and interconnects with the ANR Patterson Offshore pipeline system at Vermillion Block 397.

Second Quarter Ended June 30, 2004 Compared With Second Quarter Ended June 30, 2003

Natural gas pipelines and plants margin for the quarter ended June 30, 2004, was $9.7 million higher than in the same period in 2003. This increase was primarily due to a $9.8 million increase in margin for our Texas intrastate pipeline system. During the second quarter of 2003, the Texas intrastate pipeline system experienced an unexplained increase in fuel used on the system, which resulted in a $3.0 million reduction in margin. Additionally, at June 30, 2003, we had an imbalance payable position of 6.3 Bcf that resulted in a $3.9 million revaluation impact, which also decreased margin. During the second quarter of 2004, margin on the Texas intrastate system was not impacted by those same events as our fuel use on the system had returned to historical levels and our imbalance position at June 30, 2004, had decreased significantly to a payable position of 0.4 Bcf. Additionally, we had a $2.3 million increase in margin at our Texas intrastate pipeline system related to an increase in base business over the same period in 2003. Margin also increased by $2.3 million at our Chaco processing plant due to higher NGL prices as compared to the same period in 2003. Partially offsetting these increases was a $1.6 million decrease in margin at our Indian Basin gas plant attributable to lower volumes due to plant maintenance in the second quarter of 2004.

Operating expenses excluding depreciation, depletion and amortization for the quarter ended June 30, 2004, were $3.9 million higher than the same period in 2003 primarily due to timing of expenditures associated with normal recurring operating expenses and an increase in allocated administrative costs, including merger-related costs and directors and officers liability insurance. These increases were partially offset by a $2.0 million increase in our allowance for doubtful accounts recorded in 2003.

Six Months Ended June 30, 2004 Compared With Six Months Ended June 30, 2003

Natural gas pipelines and plants margin for the six months ended June 30, 2004, was $19.8 million higher than in the same period in 2003. This increase was primarily due to a $21.5 million increase in margin for our Texas intrastate pipeline system. During the six months ended June 30, 2003, the Texas intrastate pipeline system experienced an unexplained increase in fuel used on the system, which resulted in a $7.2 million reduction in margin. Additionally, at June 30, 2003, we had an imbalance payable position of 6.3 Bcf that resulted in a $9.4 million revaluation impact, which also decreased margin. During the six months ended June 30, 2004, margin on the Texas intrastate system was not impacted by those same events as our fuel use on the system had returned to historical levels and our imbalance position at June 30, 2004, had decreased significantly to a payable position of 0.4 Bcf. Additionally, we had a $4.4 million increase in margin at our Texas intrastate pipeline system related to an increase in base business over the same period in 2003. Margin also increased by $3.5 million due to an increase in volumes during 2004 on our San Juan gathering system and $2.4 million due to additional volumes on our Falcon Nest pipeline. San Juan gathering volumes were higher in 2004 as compared to 2003 due to a turbine outage at the Blanco plant in 2003 which resulted in volumes being shut in on the gathering system. Volumes are up on the Falcon Nest pipeline reflecting a full six months of operation as compared to 2003. Partially offsetting these increases was a $3.0 million decrease in margin at our Indian Basin gas plant attributable to lower volumes due to plant maintenance in the second quarter of 2004 and colder temperatures in the first quarter of 2004. These increases were also offset by an additional $3.0 million of increased fuel costs at our Permian Basin gathering systems over the same period in 2003.

Operating expenses excluding depreciation, depletion and amortization for the quarter ended June 30, 2004, were $9.8 million higher than the same period in 2003 primarily due to timing of expenditures associated with normal recurring operating expenses and an increase in allocated administrative costs, including merger-related costs and directors and officers liability insurance. These increases were partially offset by a $2.0 million increase in our allowance for doubtful accounts recorded in 2003.

Oil and NGL Logistics

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands, except for volumes)			
Oil and NGL logistics revenues	$ 19,817	$ 16,009	$ 35,005	$ 27,977
Cost of natural gas and other products	(318)	(103)	(1,278)	(103)
Oil and NGL logistics margin	19,499	15,906	33,727	27,874
Operating expenses excluding depreciation, depletion, and amortization	(6,247)	(5,531)	(13,009)	(9,861)
Other income and cash distributions from unconsolidated affiliates in excess of earnings[(1)]	—	2,522	2	6,484
Performance cash flows	$ 13,252	$ 12,897	$ 20,720	$ 24,497
Liquid Volumes (Bbls/d)				
NGL Fractionation Plants	69,480	58,770	72,812	62,880
NGL Pipeline Systems	52,044	37,311	39,760	28,185
Allegheny Oil Pipeline	32,117	14,053	30,656	15,763
Typhoon Oil Pipeline	30,546	31,238	31,950	24,913
Unconsolidated affiliate				
Poseidon Oil Pipeline[(2)]	104,582	134,751	103,082	144,222
Total liquid volumes	288,769	276,123	278,260	275,963

(1) Earnings from unconsolidated affiliates for the quarters ended June 30, 2004 and 2003, were $1,379 thousand and $2,361 thousand. Earnings from unconsolidated affiliates for the six months ended June 30, 2004 and 2003, were $3,169 thousand and $5,048 thousand.

(2) Represents 100 percent of Poseidon volumes.

The majority of the earnings from the oil and NGL logistics segment are generated from volume-based fees for providing transportation of oil and NGL and fractionation of NGL. However, many of the agreements with the customers on our oil pipelines require that we purchase oil from the customer at the inlet of our pipeline for an index price, less an amount that compensates us for transportation services, and resell the oil to the customer at the outlet of our pipeline at the same index price. We record these transactions based on the net amount billed to our customers resulting in these transactions reflecting a fee for transportation services. For these reasons, we feel that gross margin (revenue less cost of natural gas and other products) provides a more accurate and meaningful basis for analyzing operating results for this segment.

Margin is driven by product pricing for both oil and NGL and by volumes. Both oil and NGL volumes are impacted by natural resource decline as well as increases in new production. Volumes at our NGL fractionation plants are significantly impacted by processing economics, which are driven by the difference between natural gas prices and NGL prices.

Typhoon Oil Pipeline, a wholly owned subsidiary, has transportation agreements with BHP and ChevronTexaco which provide that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. As disclosed in our 2003 Annual Report on Form 10-K, as amended, we now record revenue from these buy/sell transactions upon delivery of the oil based on the net amount billed to the producers. For the quarter and six months ended June 30, 2003, we reduced by $73.1 million and $121.9 million our revenues and cost of natural gas and other products to conform to the current period presentation. This revision had no effect on operating income, net income, performance cash flows or partners' capital.

In July 2004, we completed our construction of the Marco Polo oil pipeline. We now own interests in four offshore oil pipeline systems with a combined capacity of approximately 755 MBbls/d, up from 635 MBbls/d, of oil with the addition of pumps and the use of friction reducers.

Marco Polo Oil Pipeline

The Marco Polo oil pipeline is a 36-mile, 14-inch oil pipeline that supports the Marco Polo TLP. The Marco Polo oil pipeline has a capacity of 120 MBbls/d and interconnects with our Allegheny oil pipeline in Green Canyon Block 164. We expect an increase in transportation revenues in the second half of 2004 derived from producer transportation on this system.

Front Runner Oil Pipeline

In July 2004, Poseidon, our 36 percent owned joint venture, completed construction of its 36-mile, 14-inch Front Runner oil pipeline and first production is anticipated in the fourth quarter of 2004. The new oil pipeline has a capacity of 65 MBbls/d and connects the Front Runner platform with Poseidon's existing system at Ship Shoal Block 332. In October 2003, Poseidon began withholding distributions to fund its capital expenditures related to its Front Runner project. Since Poseidon has completed its construction of the Front Runner oil pipeline, we expect to start receiving distributions again in late 2004 or early 2005.

Cameron Highway Oil Pipeline

The Cameron Highway oil pipeline will be a 390-mile crude oil pipeline system with a capacity of approximately 500 MBbls/d. In July 2003, we sold a 50 percent interest in our Cameron Highway oil pipeline to Valero Energy Corporation (Valero) for $86 million, forming a joint venture with Valero. Valero paid us approximately $70 million at closing, including $51 million representing 50 percent of the capital investment expended through that date for the pipeline project. Valero will pay us an additional $5 million once the system is completed, which is expected in the fourth quarter of 2004. We expect to reflect this amount as a gain from the sale of long-lived assets in the fourth quarter of 2004. In addition, we will receive another $11 million by the end of 2006. We expect to reflect this amount as a gain from the sale of long-lived assets in the period it is earned. We do not expect to receive distributions from Cameron Highway until 2006 due to the debt service covenants on Cameron Highway's project finance facility.

Additionally, in July 2004, we announced that Cameron Highway had executed an agreement with Kerr-McGee for the dedication and movement of crude oil production from the Constitution and Ticonderoga fields, along with other future production from several undeveloped blocks in the south Green Canyon area of the deepwater trend of the Gulf of Mexico. Under the terms of the agreement, production from Kerr-McGee's interest in Constitution, Ticonderoga and surrounding undeveloped blocks is dedicated to the Cameron Highway oil pipeline system for the life of the reserves. Cameron Highway expects volumes from these fields in the first half of 2006. Further, we will construct and own a 70-mile, 16-inch oil pipeline which will connect the Constitution and Ticonderoga fields with the Cameron Highway oil pipeline at the new Ship Shoal 332B platform. We plan to install the new oil pipeline in the summer of 2005, with first production scheduled for the first half of 2006.

Second Quarter Ended June 30, 2004 Compared With Second Quarter Ended June 30, 2003

For the quarter ended June 30, 2004, margin was $3.6 million higher than the same period in 2003. Margin attributable to our NGL pipeline systems was up $2.8 million due to an increase in volumes as our NGL pipeline had been down for maintenance through the third quarter of 2003. In addition, margin from our NGL fractionation plants increased $1.0 million due to higher volumes resulting from improved processing economics at the plants in 2004.

Operating expenses excluding depreciation, depletion and amortization for the quarter ended June 30, 2004, were $0.7 million higher than the same period in 2003 primarily due to an increase in allocated administrative costs, including merger-related costs and directors and officers liability insurance.

Other income and cash distributions from unconsolidated affiliates in excess of earnings for the quarter ended June 30, 2004, declined $2.5 million. As discussed above, Poseidon was withholding distributions to fund its capital expenditures related to its Front Runner project. Poseidon completed its Front Runner project in July 2004 and we expect to start receiving distributions in late 2004 or early 2005.

Six Months Ended June 30, 2004 Compared With Six Months Ended June 30, 2003

For the six months ended June 30, 2004, margin was $5.9 million higher than the same period in 2003. Margin attributable to our NGL pipeline systems was up $4.2 million due to an increase in volumes as our NGL pipeline had been down for maintenance through the third quarter of 2003. In addition, margin from our NGL fractionation plants increased $1.8 million due to higher volumes resulting from improved processing economics at the plants in 2004.

Operating expenses excluding depreciation, depletion and amortization for the six months ended June 30, 2004, were $3.1 million higher than the same period in 2003. This increase was primarily due to timing of expenditures associated with normal recurring operating expenses and an increase in allocated administrative costs, including merger-related costs and directors and officers liability insurance.

Other income and cash distributions from unconsolidated affiliates in excess of earnings for the six months ended June 30, 2004, declined $6.5 million. As discussed above, Poseidon was withholding distributions to fund its capital expenditures related to its Front Runner project. Poseidon completed its Front Runner project in July 2004 and we expect to start receiving distributions in late 2004 or early 2005.

Natural Gas Storage

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands, except for volumes)			
Natural gas storage revenue	$11,743	$11,057	$24,193	$22,755
Cost of natural gas	(132)	132	75	(1,429)
Natural gas storage margin	11,611	11,189	24,268	21,326
Operating expenses excluding depreciation, depletion, and amortization	(3,890)	(3,121)	(7,487)	(6,257)
Other income and cash distributions from unconsolidated affiliates in excess of earnings	—	—	13	—
Minority interest	—	—	(12)	—
Performance cash flows	$ 7,721	$ 8,068	$16,782	$15,069
Firm storage (Bcf)				
Average working gas capacity available	13.5	13.5	13.5	13.5
Average firm subscription	12.8	12.7	12.9	12.7
Average monthly commodity volumes[1]	4.8	4.7	5.5	4.8
Interruptible storage (Bcf)				
Contracted volumes	0.4	0.4	0.3	0.2
Average monthly commodity volumes[1]	1.4	0.2	1.0	0.2

(1) Combined injections and withdrawals volumes.

At our Petal and Hattiesburg natural gas storage facilities, we collect fixed and variable fees for providing storage services. We incur expenses, which are reflected as cost of natural gas, as we maintain these volumetric imbalance receivables and payables, all of which are valued at current gas prices. Cost of natural gas reflects the initial imbalance and the monthly revaluation of these amounts based on the monthly change in natural gas prices. For these reasons, we believe that gross margin (revenue less cost of natural gas) provides a more accurate and meaningful basis for analyzing operating results for this segment.

Petal Conversion Project

In the second quarter of 2004, Petal executed agreements with BP Energy Company for the 1.8 Bcf of firm storage capacity in Petal's new natural gas storage cavern. The agreements will commence in October 2004, and we expect an increase in storage revenues in the fourth quarter of 2004 derived from the firm storage at Petal.

Second Quarter Ended June 30, 2004 Compared With Second Quarter Ended June 30, 2003

For the quarter ended June 30, 2004, margin was $0.4 million higher than the same period in 2003 primarily due to an increase in interruptible storage services at our leased Wilson storage facility.

Operating expenses excluding depreciation, depletion and amortization for the quarter ended June 30, 2004, were $0.8 million higher than the same period in 2003 primarily due to an increase in allocated administrative costs, including merger-related costs and directors and officers liability insurance.

Six Months Ended June 30, 2004 Compared With Six Months Ended June 30, 2003

For the six months ended June 30, 2004, margin was $2.9 million higher than the same period in 2003, of which $1.5 million was due to an increase in interruptible storage services at our leased Wilson storage facility. In addition, there was a $1.6 million increase in margin at our Hattiesburg gas storage facility attributable to lower revaluation expense of our natural gas imbalances due to a lower imbalance position in 2004.

Operating expenses excluding depreciation, depletion and amortization for the six months ended June 30, 2004, were $1.2 million higher than the same period in 2003 primarily due to an increase in allocated administrative costs, including merger-related costs and directors and officers liability insurance.

Platform Services

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands, except for volumes)			
Platform services revenue from external customers	$ 6,290	$6,101	$12,932	$10,483
Platform services intersegment revenue	579	758	1,164	1,404
Operating expenses excluding depreciation, depletion, and amortization	(1,052)	(582)	(1,915)	(1,375)
Other income and cash distributions from unconsolidated affiliates in excess of earnings[1]	(1)	—	(2)	—
Performance cash flows	$ 5,816	$6,277	$12,179	$10,512
Natural gas platform volumes (MDth/d)				
East Cameron 373	111	104	111	112
Garden Banks 72	5	20	5	23
Viosca Knoll 817	5	5	5	6
Falcon Nest platform[2]	284	190	274	110
Total natural gas platform volumes	405	319	395	251
Oil platform volumes (Bbl/d)				
East Cameron 373	674	920	993	871
Garden Banks 72	706	1,102	766	1,067
Viosca Knoll 817	2,108	2,020	2,121	2,005
Falcon Nest platform[2]	936	720	872	422
Total oil platform volumes	4,424	4,762	4,752	4,365

(1) Earnings from unconsolidated affiliates for the quarter and six months ended June 30, 2004, were $1,295 thousand and $1,209 thousand.

(2) The Falcon Nest platform was placed in service in March 2003.

Our platform services segment generally earns revenue through demand fees (regular payments made by customers using our platform services regardless of volumes) and commodity charges (volume-based payments made by customers). Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a fixed period of time.

Marco Polo TLP

The Marco Polo TLP was installed in the first quarter of 2004 and commenced operations in July 2004. Deepwater Gateway L.L.C., the owner of the Marco Polo TLP, began receiving monthly demand payments of $2.1 million in April 2004 and volumetric payments started in July 2004. Additionally, in July 2004, Deepwater Gateway converted its project finance loan into a term loan with payments on the term loan beginning September 30, 2004. We expect to receive distributions in 2005 from Deepwater Gateway subject to term loan covenants.

In March 2004, Deepwater Gateway executed a binding memorandum of understanding with Eni Petroleum Exploration Co. Inc, ConocoPhillips Company and Union Oil Company of California for the processing of their 47.5 percent working interest in the K2 Field production on the Marco Polo TLP. Anadarko's 52.5 percent interest in the K2 Field was previously dedicated to the Marco Polo TLP. Also, production from Anadarko's 100 percent interest in the K2 North Field in Green Canyon Block 518 will be processed on the Marco Polo TLP. Deepwater Gateway expects to receive volumes from these fields in the first half of 2005.

Second Quarter Ended June 30, 2004 Compared With Second Quarter Ended June 30, 2003

For the quarter ended June 30, 2004, revenues were slightly higher than in the same period in 2003. The increase is primarily due to increased volumes from our Falcon Nest fixed leg platform resulting from new wells coming on line in the first quarter of 2004.

Operating expenses excluding depreciation, depletion and amortization for the quarter ended June 30, 2004, were $0.5 million higher than the same period in 2003 primarily due to an increase in allocated administrative costs, including merger-related costs and directors and officers liability insurance.

Six Months Ended June 30, 2004 Compared With Six Months Ended June 30, 2003

For the six months ended June 30, 2004, revenues were $2.2 million higher than in the same period in 2003. An increase in volumes from new wells in the first quarter of 2004 resulted in higher margins of $4.1 million at our Falcon Nest Platform. Partially offsetting this increase were lower revenues of $1.9 million from East Cameron 373 resulting from lower demand fees.

Operating expenses excluding depreciation, depletion and amortization for the six months ended June 30, 2004, were $0.5 million higher than the same period in 2003 primarily due to an increase in allocated administrative costs, including merger-related costs and directors and officers liability insurance.

Other, Non-Segment Results

Our oil and natural gas production interests in the Garden Banks 72, Garden Banks 117, Viosca Knoll 817 and West Delta 35 Blocks principally comprise the non-segment activity. Production from these properties, except West Delta 35, is gathered, transported, and processed through our pipeline systems and platform facilities. Oil and natural gas production volumes are produced and sold to various third parties at the market price. Revenue is recognized in the period of production, all of which is sold to our customers. These revenues may be impacted by market changes, hedging activities, and natural declines in production reserves. We are reducing our oil and natural gas production activities by not acquiring additional properties due to their higher risk profile. Accordingly, our focus is to maximize the production from our existing portfolio of oil and natural gas properties.

Also included in other, non-segment results for the six months ended June 30, 2004 and for the quarter and six months ended June 30, 2003, are the quarterly payments we received from El Paso Corporation in connection with the sale of some of our Gulf of Mexico assets in January 2001. The sale of these assets occurred as a result of a FTC order related to El Paso Corporation's merger with The Coastal Corporation. El Paso Corporation agreed to pay us $2.25 million per quarter through the fourth quarter of 2003 and $2 million in the first quarter of 2004. As of March 31, 2004, all required payments had been received and, as a result, future performance cash flows for other non-segment activities will be lower compared to prior periods.

Second Quarter Ended June 30, 2004 Compared With Second Quarter Ended June 30, 2003

Performance cash flows related to other, non-segment results for the quarter ended June 30, 2004, were $0.3 million higher than the same period in 2003 primarily due to a decrease in operating expenses in 2004 of $2.8 million associated with the allocation of costs to our business segments. The decrease in operating expenses was offset by the discontinuation of the quarterly payments we received from El Paso Corporation in connection with the sale of some of our Gulf of Mexico assets in January 2001. We received the final payment of $2.0 million in the first quarter of 2004.

Six Months Ended June 30, 2004 Compared With Six Months Ended June 30, 2003

Performance cash flows related to other non-segment results for the six months ended June 30, 2004, were $0.4 million higher than the same period in 2003 primarily due to a decrease in operating expenses in 2004 of $3.8 million associated with the allocation of costs to our business segments. The decrease in operating expenses was offset by the discontinuation of the quarterly payments we received from El Paso Corporation in connection with the sale of some of our Gulf of Mexico assets in January 2001. We received the final payment of $2.0 million in the first quarter of 2004.

Depreciation, Depletion, and Amortization

Depreciation, depletion and amortization for the quarter ended June 30, 2004 was $1.2 million higher than the same period in 2003 primarily due to an increase in depreciation expense of $1.2 million related to assets placed in service during 2003, including our communication assets placed in service in October 2003 and the Viosca Knoll pipeline extension placed in service in December 2003. Additionally, we had an increase in depreciation expense of $0.7 million associated with an increase in the costs assigned to the San Juan assets we purchased in November 2002 as a result of the final purchase price allocation. This increase in depreciation expense was partially offset by a decrease in depreciation expense of $0.6 million due to our revised estimate for the depreciable life of the Chaco plant resulting from our exchange transaction with El Paso Corporation in October 2003.

Depreciation, depletion and amortization for the six months ended June 30, 2004 was $3.8 million higher than the same period in 2003 primarily due to an increase in depreciation expense of $2.3 million from assets placed in service during 2003, including our communication assets placed in service in October 2003 and the Viosca Knoll pipeline extension placed in service in December 2003. Additionally, we had an increase in depreciation expense of $0.3 million resulting from additional capital expenditures on our Falcon Nest pipeline and platform, $1.5 million associated with an increase in the costs assigned to the San Juan assets we purchased in November 2002 as a result of the final purchase price allocation and increased depletion of $0.8 million resulting from the true-up of reserves based on revised reserve estimates. This increase in depreciation expense was partially offset by a decrease in depreciation expense of $1.1 million due to our revised estimate for the depreciable life of the Chaco plant resulting from our exchange transaction with El Paso Corporation in October 2003.

Interest and Debt Expense

Interest and debt expense, net of capitalized interest, for the quarter ended June 30, 2004, was approximately $5.1 million lower than the same period in 2003. This decrease is primarily due to the redemption of a portion of our senior subordinated notes in April 2004 and December 2003 and the full redemption of our $175 million 10⅜% senior subordinated notes due 2009 in June 2004. Additionally, interest and debt expense decreased as a result of lower weighted average interest rates on our revolving credit facility and senior secured term loan and the repayment of our GulfTerra Holding term loan during the third quarter of 2003. Partially offsetting these decreases were increased interest expenses associated with the additional senior secured term loan we obtained in May 2004, the senior notes we issued in July 2003 and the increased weighted average debt outstanding on our revolving credit facility and our already-existing senior secured term loan.

Interest and debt expense, net of capitalized interest, for the six months ended June 30, 2004, was approximately $11.6 million lower than the same period in 2003. This decrease is primarily due to the redemption of a portion of our senior subordinated notes in April 2004 and December 2003 and the full redemption of our $175 million 10$^{3}/_{8}$% senior subordinated notes due 2009 in June 2004. Additionally, interest and debt expense decreased as a result of lower weighted average interest rates on our revolving credit facility and senior secured term loan, decreased weighted average debt outstanding on our revolving credit facility, the repayment of our GulfTerra Holding term loan during the third quarter of 2003 and the repayment of our senior secured acquisition term loan in March 2003. Partially offsetting these decreases were increased interest expenses associated with the additional senior secured term loan we obtained in May 2004, the senior notes we issued in July 2003 and the increased weighted average debt outstanding on our already-existing senior secured term loan.

Capitalized interest for the quarter and six months ended June 30, 2004, was $3.9 million and $7.6 million, representing increases of $1.3 million and $3.1 million over the comparable prior periods. The increase is the result of higher expenditures related to our construction projects, primarily the Marco Polo natural gas and oil pipelines, the Phoenix gathering system and the Cameron Highway oil pipeline system. This increase was partially offset by reduced expenditures on construction projects placed into service in 2003, primarily the Viosca Knoll pipeline extension and the Falcon Nest natural gas pipeline and platform, and on the Marco Polo TLP which was installed in the first quarter of 2004.

Loss Due to Early Redemptions of Debt

In June 2004, we redeemed all of our outstanding $175 million aggregate principal amount of 10$^{3}/_{8}$% senior subordinated notes due 2009 and we recognized a loss of $12.2 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs.

In April 2004, we redeemed approximately $39.1 million in principal amount of our 8$^{1}/_{2}$% senior subordinated notes due June 2010 and we recognized a loss of $4.1 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs.

In March 2003, we repaid our $237.5 million senior secured acquisition term loan which was due in May 2004 and recognized a loss of $3.8 million related to the write-off of unamortized debt issuance costs related to this loan.

Cumulative Effect of Accounting Change

Our cumulative effect of accounting change for the six months ended June 30, 2003, reflects our adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations,* on January 1, 2003.

Commitments and Contingencies

See Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

None.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements. These statements are subject to risks and uncertainties. Forward-looking statements include information concerning possible or assumed future results of operations. These statements may relate to information or assumptions about:

- earnings per unit;
- capital and other expenditures;
- cash distributions;
- financing plans;
- capital structure;
- liquidity and cash flow;
- pending legal proceedings and claims, including environmental matters;
- future economic performance;
- operating income;
- cost savings;
- management's plans; and
- goals and objectives for future operations.

Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2003, and our other filings with the SEC. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and made in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we express an expectation or belief as to future results, such expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. These statements relate to analyses and other information which are based on forecasts of future results and estimates of amounts not yet determinable. These statements also relate to our future prospects, developments and business strategies. These forward-looking statements are identified by their use of terms and phrases such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project," "will," and similar terms and phrases, including references to assumptions. These forward-looking statements involve risks and uncertainties that may cause our actual future activities and results of operations to be materially different from those suggested or described.

These risks may also be specifically described in our Current Reports on Form 8-K and other documents filed with the SEC. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information or otherwise. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those expected, estimated or projected.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, our quantitative and qualitative disclosures about market risks reported in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2003, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

A majority of our commodity purchases and sales, which relate to sales of oil and natural gas associated with our production operations, purchases and sales of natural gas associated with pipeline operations, sales of natural gas liquids and purchases or sales of gas associated with our processing plants and our gathering activities, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities.

We estimate the entire $11.2 million of unrealized losses included in accumulated other comprehensive income at June 30, 2004, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next six months. When our derivative financial instruments are settled, the related amount in accumulated other comprehensive income is recorded in the income statement in operating revenues, cost of natural gas and other products, or interest and debt expense, depending on the item being hedged. The effect of reclassifying these amounts to the income statement line items is recording our earnings for the period related to the hedged items at the "hedged price" under the derivative financial instruments.

In February and August 2003, we entered into derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. As of June 30, 2004 and December 31, 2003, the fair value of these cash flow hedges was a liability of $7.3 million and $5.8 million, as the market price at those dates was higher than the hedge price. For the quarter and six months ended June 30, 2004, we reclassified approximately $2.3 million and $4.0 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. These reclassifications are included in our natural gas pipelines and plants segment. No ineffectiveness exists in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

During 2003, we entered into additional derivative financial instruments to hedge a portion of our business' exposure to changes in NGL prices during 2004. We entered into financial swaps for 6,000 barrels per day for the period from August 2003 to September 2004. The average fixed price received is $0.47 per gallon for 2004 while we pay a monthly average floating price based on the OPIS average price for each month. As of June 30, 2004 and December 31, 2003, the fair value of these cash flow hedges was a liability of $3.9 million and $3.3 million. For the quarter and six months ended June 30, 2004, we reclassified approximately $2.4 million and $4.6 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income to earnings. These reclassifications are included in our natural gas pipelines and plants segment. No ineffectiveness exists in this hedging relationship because all purchase and sales prices are based on the same index and volumes as the hedge transaction.

In connection with our GulfTerra Intrastate Alabama operations, we had fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2003 to offset the risk of increasing natural gas prices. For January and February 2004, we contracted to purchase 20,000 MMBtu and for March 2004, we contracted to purchase 15,000 MMBtu. The average fixed price paid during 2004 was $5.28 per MMBtu while we received a floating price based on the SONAT-Louisiana index. In March 2004, these cash flow hedges expired and we reclassified a gain of approximately $45 thousand from accumulated other comprehensive income to earnings. This reclassification is included in our natural gas pipelines and plants segment. No ineffectiveness existed in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

In July 2003, to achieve a more balanced mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we paid the counterparty a LIBOR based interest rate plus a spread of 4.20% and received a fixed rate of 8½%. We accounted for this derivative as a fair value hedge under SFAS No. 133. In March 2004, we terminated our fixed to floating interest rate swap with our counterparty. The value of the transaction at termination was zero, and as such, neither we, nor our counterparty, were required to make any payments. Also, neither we, nor our counterparty, have any future obligations under this transaction.

Item 4. Controls and Procedures

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls over financial reporting (Internal Controls) as of the end of the period covered by this Quarterly Report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are properly authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. Our management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our Disclosure Controls and Internal Controls are designed to provide such reasonable assurances of achieving our desired control objectives, and our principal executive officer and principal financial officer have concluded that our Disclosure Controls and Internal Controls are effective in achieving that level of reasonable assurance.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "material weaknesses" in our Internal Controls, or whether we had identified any acts of fraud involving personnel who have a significant role in our Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to the Audit and Conflicts Committee of our general partner's board of directors and our independent auditors and to report on related matters in this section of the Quarterly Report. The principal executive officer and principal financial officer note that there have not been any significant changes in Internal Controls or in other factors that could significantly affect Internal Controls, including any corrective actions with regard to material weaknesses.

We are currently undergoing a comprehensive effort to ensure compliance with Section 404 of the Sarbanes Oxley Act of 2002 for the year ended December 31, 2004. This effort includes internal control documentation and review under the direction of senior management and the Audit and Conflicts Committee of our general partner's board of directors. During the course of these activities, we have identified certain internal control issues which management believes need to be improved. These control issues are, in large part, the result of our increased size and complexity as a result of acquisitions and continued business growth.

The review has not identified any material weaknesses in internal control as defined by the Public Company Accounting Oversight Board. However, we have made improvements to our internal controls over financial reporting as a result of our review efforts and will continue to do so. These improvements include formalizing and communicating certain policies and procedures, strengthening system security access and segregation of duties, and increasing the frequency of monitoring controls.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that the Disclosure Controls are effective to ensure that material information relating to us and our consolidated subsidiaries is made known to our management, including the principal executive officer and principal financial officer, on a timely basis.

Officer Certifications. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as Exhibits to this Quarterly Report.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

Item 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

On July 29, 2004, we held a special meeting of our common and Series C unitholders to vote upon the adoption and approval of the Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners, L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C., to combine our business with that of Enterprise by merging us into a wholly-owned subsidiary of Enterprise. The merger agreement was approved by our common and Series C unitholders with the following numbers of votes cast: 37,353,838 votes were cast in favor of approval, 597,941 votes were cast against approval and there were 180,352 abstentions.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by a "*"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" represent a management contract or compensatory plan or arrangement.

Exhibit Number	Description
2.A	— Merger Agreement, dated as of December 15, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Company, L.L.C., Enterprise Products Partners, L.P., Enterprise Products GP, LLC, and Enterprise Products Management LLC (Exhibit 2.1 to our Current Report on Form 8-K filed December 15, 2003).
3.A	— Amended and Restated Certificate of Limited Partnership dated February 14, 2002; Amendment dated April 30, 2003 (Exhibit 3.A.1 to our 2003 First Quarter Form 10-Q); Amendment 2 dated July 25, 2003 (Exhibit 3.A.1 to our 2003 Second Quarter Form 10-Q).
3.A.1	— Conformed Certificate of Limited Partnership (Exhibit 3.A.1 to our 2003 Third Quarter Form 10-Q).

Exhibit Number	Description
3.B	— Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Current Report on Form 8-K dated March 6, 2001); First Amendment dated November 27, 2002 (Exhibit 3.B.1 to our Current Report on Form 8-K dated December 11, 2002); Second Amendment dated May 5, 2003 (Exhibit 3.B.2 to our Current Report on Form 8-K dated May 13, 2003); Third Amendment dated May 16, 2003 (Exhibit 3.B.3 to our Current Report on 8-K dated May 16, 2003); Fourth Amendment dated July 23, 2003 (Exhibit 3.B.1 to our 2003 Second Quarter Form 10-Q); Fifth Amendment dated August 21, 2003 (Exhibit 3.B.1 to our Current Report on Form 8-K dated October 10, 2003).
3.B.1	— Conformed Partnership Agreement (Exhibit 3.B.2 to our Current Report on Form 8-K dated October 10, 2003).
4.E	— Indenture dated as of May 17, 2001 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, The Subsidiary Guarantors named therein and the Chase Manhattan Bank, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.1 to our 2002 First Quarter Form 10-Q), Second Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.2 to our 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.E.3 to our 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.E.1 to our Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.E.2 to our Current Report on Form 8-K dated March 19, 2003); Sixth Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.E.1 to our 2003 Second Quarter Form 10-Q).
4.G	— Registration Rights Agreement by and between El Paso Corporation and GulfTerra Energy Partners, L.P. dated as of November 27, 2002 (Exhibit 4.G to our Current Report on Form 8-K dated December 11, 2002).
4.I	— Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (Exhibit 4.I to our Current Report on Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.I.1 to our Current Report on Form 8-K dated March 19, 2003). Second Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.I.1 to our 2003 Second Quarter Form 10-Q).
4.K	— Indenture dated as of March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee dated as of March 24, 2003 (Exhibit 4.K to our Quarterly Report on Form 10-Q dated May 15, 2003), First Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.K.1 to our 2003 Second Quarter Form 10-Q).
4.L	— Indenture dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.L to our 2003 Second Quarter Form 10-Q).
4.M	— Unitholder Agreement dated May 16, 2003 by and between GulfTerra Energy Partners, L.P. and Fletcher International, Inc. (Exhibit 4.L to our Current Report on Form 8-K filed May 19, 2003).

Exhibit Number	Description
4.N	— Exchange and Registration Rights Agreement by and among GulfTerra Energy Company, L.L.C., GulfTerra Energy Partners, L.P. and Goldman Sachs & Co. dated as of October 2, 2003 (Exhibit 10.U to our Current Report on Form 8-K dated October 10, 2003).
*10.N.1	— Term Loan Addendum for Series B-2 Additional Term Loans dated as of May 20, 2004.
*10.X+	— Form of Repurchase Agreement between GulfTerra Energy Partners, L.P. and each of the individuals named in Schedule A thereto.
*31.A	— Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	— Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.A	— Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.B	— Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

We hereby undertake, pursuant to Regulation S-K Items 601(b), paragraph (4)(iii), to furnish to the U.S. Securities and Exchange Commission, upon request, all constituent instruments defining the rights of holders of our long-term debt not filed herewith for the reason that the total amount of securities authorized under any such instruments does not exceed 10 percent of our total consolidated assets.

(b) Reports on Form 8-K

We filed a Current Report on Form 8-K dated April 20, 2004 to announce that Enterprise and El Paso Corporation amended their agreement with regard to their ownership of the merged companies' general partner upon completion of the merger.

We filed a Current Report on Form 8-K dated May 5, 2004 to notify our unitholders and the market that we had identified a potential revision to the accounting for the cash settlement of natural gas imbalance receivables on our Texas Intrastate pipeline system, which we acquired in April 2002.

We filed a Current Report on Form 8-K dated May 7, 2004 to file the one year audited balance sheet of GulfTerra Energy Company, L.L.C., our general partner, as of December 31, 2003, which is incorporated by reference into our Registration Statement on Form S-3 (No. 333-81772, No. 333-85987, No. 333-107082 and No. 333-110116) and on Form S-8 (No. 333-70617).

We filed a Current Report on Form 8-K dated June 2, 2004 to announce our redemption of the entire $175 million outstanding aggregate principal amount of our 10$\frac{3}{8}$% senior subordinated notes due 2009 and to announce we had obtained a $200 million senior secured term loan in addition to our existing $300 million senior secured term loan.

We filed a Current Report on Form 8-K dated June 25, 2004 to announce our subsidiary, Petal Gas Storage, L.L.C. will hold a non-binding open season from Wednesday July 7, 2004, through Thursday, July 22, 2004, to determine market interest for up to 5.0 Bcf of firm natural gas capacity at its Petal Gas Storage facility, and up to 500,000 MMBtu/d of firm transportation on the Petal pipeline, all available in the third quarter of 2007. The storage and transportation capacities became available when the Letter of Intent between Petal and Southern Natural Gas Company expired in June 2004.

We filed a Current Report on Form 8-K dated July 8, 2004 to announce that we had reached a definitive agreement to construct, own, and operate oil and gas export pipelines to provide firm gathering services from the Constitution field, which is 100 percent owned by Kerr-McGee.

We filed a Current Report on Form 8-K dated July 16, 2004 to announce that Cameron Highway Oil Pipeline Company, a venture jointly owned by us and Valero, executed an agreement with Kerr-McGee for the dedication and movement of crude oil production from the Constitution and Ticonderoga fields, along with other future potential production from several undeveloped blocks in the south Green Canyon area of the deepwater trend of the Gulf of Mexico.

We filed a Current Report on Form 8-K dated July 20, 2004 to announce that our jointly owned Marco Polo Tension Leg Platform commenced processing initial oil and gas production from Anadarko Petroleum Corporation's Marco Polo field in Green Canyon Block 608.

We filed a Current Report on Form 8-K dated July 21, 2004 to announce that we commenced operations of the Phoenix gas pipeline and recently received initial production from the Red Hawk field located in the Garden Banks area of the central deepwater trend in the Gulf of Mexico.

We filed a Current Report on Form 8-K dated July 30, 2004 to announce that our unitholders approved the proposed merger between us and Enterprise in our unitholder meeting held July 29, 2004.

We also furnished to the SEC Current Reports on Form 8-K under Item 9 and Item 12. Current Reports on Form 8-K under Item 9 and Item 12 are not considered to be "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 and are not subject to the liabilities of that section.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GULFTERRA ENERGY PARTNERS, L.P.

Date: August 9, 2004

By: /s/ William G. Manias

William G. Manias
Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 9, 2004

By: /s/ Kathy A. Welch

Kathy A. Welch
Vice President and Controller
(Principal Accounting Officer)